CONSULTANT REPORT

WESTCARB PHASE III FINAL REPORT

Summary of California Activities

Prepared for: California Energy Commission
Prepared by: California Institute of Energy and Environment

JULY 2016
CEC-500-2016-053

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ACKNOWLEDGMENTS

We wish to acknowledge the support of this work by the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) under cooperative agreement DE-FC26-05NT42593 and by the California Energy Commission. This project is managed and administered by the California Energy Commission and also funded in part by cost-sharing industry and government partners. We also wish to thank all of WESTCARB's member organizations for their participation and input to WESTCARB's activities.

We also wish to acknowledge the contributions of numerous colleagues in providing concepts, data, reference materials, and/or peer reviews in support of the research described in this report. In particular, we appreciate the contributions of John Henry Beyer and many other scientists (LBNL); William Bourcier, Jeff Wagoner and Katie Myers (LLNL); Pat Ross (Princeton Natural Gas); engineers at Stone & Webster (now CB&I); Larry Myer (LTI); Lorraine Hwang (CIEE); Kevin O'Brien (Energy Commercialization, LLC); Dorota Keverian (Clinton Foundation); George Peridas (NRDC); Terry Surles (formerly University of Hawaii and University of Nevada); staff scientists at the California Geological Survey; and geologists and engineers at Sandia Technologies and Schlumberger Carbon Services. At the Energy Commission, we appreciate the efforts of Commissioner Jim Boyd, Susan Brown, Cheryl Closson, Rachel Grant-Kiley, Mike Gravely, Jack Janes, Elizabeth Keller, Martha Krebs, Bryan Lee, John Reed, Linda Spiegel, David Stoms, Connie Sichon, and Laurie ten Hope. At NETL and DOE, we would like to thank Dawn Deel, Brian Dressel, John Litynski, Mark Ackiewicz, and Traci Rodosta.

PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

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- Transportation

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ABSTRACT

WESTCARB, the West Coast Regional Carbon Sequestration Partnership, is one of seven regional partnership projects awarded in three phases by the U.S. Department of Energy to promote research and development of carbon capture utilization and storage technology. The California Energy Commission administered and co-funded WESTCARB from 2003 to 2015. During Phase III, which lasted from 2008 to 2015, WESTCARB conducted research in seven areas:

1. Detailed characterization of geologic carbon dioxide storage, in high-potential formations in California's central valley and an overview of offshore storage resources.
2. Site characterization at King Island, a depleted natural gas field.
3. Site characterization at Kimberlina, a pilot-scale oxy-combustion power plant capable of carbon dioxide capture and a potential saline formation storage site in the San Joaquin Basin.
4. The potential of carbon utilization technologies that address California's greenhouse gas reduction goals and provide economic or environmental co-benefits.
5. Updates to the WESTCARB regional database of carbon dioxide point sources and storage resources.
6. Engineering-economic assessments of applying carbon capture utilization and storage to California natural gas combined cycle power plants.
7. Issues with implementation of carbon capture utilization and storage, including technical and nontechnical factors.

The findings from WESTCARB's Phase III research demonstrate that carbon capture utilization and storage is a viable technology that substantially reduces carbon dioxide emissions from large industrial sources. Future policy and technology constraints may keep carbon capture costs higher than near-term alternatives for greenhouse gas reduction.

Nontechnical factors that also impede or delay the commercial adoption of carbon capture utilization and storage in the WESTCARB region include: (1) lack of policy "parity" for carbon capture relative to other technologies for meeting California's greenhouse gas reduction goals, and (2) unclear guidelines for procedures permitting regulatory compliance and acquisition of salable credits for the cap-and-trade or low-carbon fuel standard programs.

Keywords: WESTCARB, CCS, CCUS, carbon capture, carbon utilization, geologic carbon storage, carbon sequestration, greenhouse gas emissions

Please use the following citation for this report:

Burton, Elizabeth, Niall Mateer, Richard Myhre, and Marian Stone. 2016. ***WESTCARB Phase III Final Report: Summary of California Activities***. California Energy Commission. Publication Number: CEC-500-2016-053.

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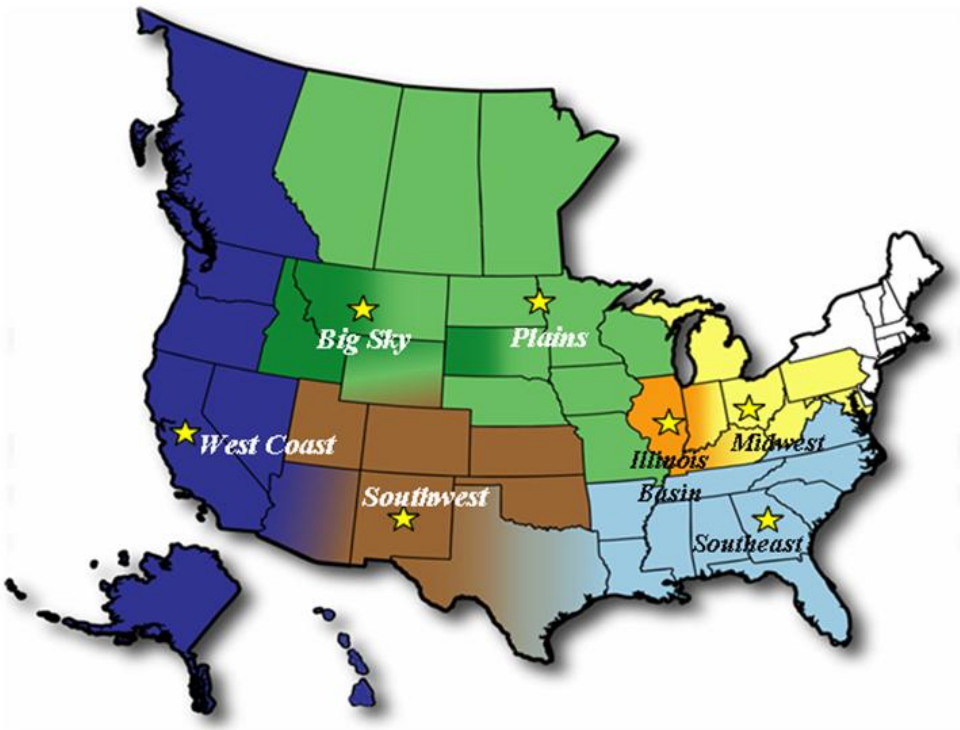
EXECUTIVE SUMMARY

Introduction

The West Coast Regional Carbon Sequestration Partnership (WESTCARB) is one of seven partnerships projects established by the U.S. Department of Energy (DOE) in 2003 to conduct research and support the development of technologies, infrastructure, and regulations for carbon capture utilization and storage (CCUS) throughout different geographic regions of the United States and Canada (Figure 1). WESTCARB's region includes the states of Alaska, Arizona, California, Hawaii, Nevada, Oregon, Washington, and the province of British Columbia.

Figure 1: Regions of the Seven U.S. DOE Regional Carbon Sequestration Partnerships



Source: National Energy Technology Laboratory

WESTCARB is led and co-funded by the California Energy Commission, which serves as the prime contractor and principal investigator for the project. Lawrence Berkeley National Laboratory and Lawrence Livermore National Laboratory participate with funding from DOE. The two laboratories support research activities by providing technical expertise, state-of-the-art testing, and high-performance computing facilities. The California Institute for Energy and Environment (CIEE) at the University of California and the consulting firm of Bevilacqua-Knight, Inc. (BKi) provided technical and administrative support to WESTCARB. WESTCARB's membership has grown to 100 organizations representing industry, academia, consulting companies, environmental organizations, and government agencies.

The work plan for each DOE partnership project was divided into three phases. During Phase I, from 2003 to 2005, WESTCARB assessed regional carbon dioxide (CO_2) storage resource potential, including geologic and terrestrial "sinks." In Phase II, from 2005 to 2011, several pilot-scale projects for both terrestrial and geologic carbon storage constituted the major focus, along with additional storage resource studies. This report covers Phase III activities, from 2008 to 2015, which are summarized below.

Project Summaries

Studies Impacting Geologic Carbon Sequestration Potential in California

The Department of Conservation's California Geological Survey (CGS) led WESTCARB Phase I and II studies that provided an initial screening of the geologic sequestration potential of California's onshore sedimentary basins and a regional evaluation of sequestration potential in the southern Sacramento Basin. During Phase III, CGS conducted analyses to determine: (1) the geologic storage potential of California's offshore basins, (2) the impacts of the U.S. Environmental Protection Agency's (USEPA) underground drinking water standard of 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) on potential sequestration resource estimates in selected California basins, and (3) the impacts of compartmentalization within oil and gas fields on carbon storage potential in depleted hydrocarbon reservoirs. Two sites were then chosen for more detailed studies of the potential for large-scale storage.

Site Characterization at Kimberlina

The first Phase III site to be characterized was at the Kimberlina Power Plant in the San Joaquin Valley near Bakersfield. In collaboration with Clean Energy Systems, WESTCARB undertook a feasibility and risk assessment study of the site for a large-volume CO_2 capture and storage demonstration. Kimberlina lies within California's prolific oil-bearing region; thus, significant numbers of wells surrounding the site provided an extensive dataset to construct a geologic model of the site. Simulations were made to assess the potential of the site to store a one million ton-CO_2 injection from a proposed 50 megawatt (MW) oxy-combustion power plant.

Geologic Characterization Well at King Island

The second site was located in the southern Sacramento Basin. WESTCARB drilled a stratigraphic well at King Island in 2011 to characterize CO_2 storage targets in a depleted natural gas reservoir and underlying saline formations. The Citizen Green Well penetrated the regionally extensive sandstone formations and their overlying shale sealing formations that form the major storage resource in the northern part of California's Central Valley. The site showed high potential for CO_2 storage based on the high permeability of the sandstones and the integrity of the overlying shales. Extensive analysis, experimentation, and simulations were performed at Lawrence Berkeley National Laboratory using the field data and core samples from the well. Results demonstrated the presence of good injectivity for CO_2 and other geologic features conducive to commercial-scale storage at the King Island site.

Seismic Hazards Risk Assessment

To increase the understanding of potential seismic hazards associated with CO_2 storage, WESTCARB conducted a seismic hazards workshop to obtain the opinions of international experts in identifying research to support development of CO_2 storage seismic safety protocols. Based on the findings of this workshop, in 2014, the Energy Commission funded a study by LBNL. The LBNL scientists surveyed the availability of data in California necessary to assess seismic hazards. This included information on faults, in situ crustal stresses, and seismic history. A second expert workshop was held in December 2014 to present available options for in-depth analysis. Given the richness of available data from the site characterization study at King Island, ongoing research efforts have leveraged information from this site.

CO_2 Utilization Potential

With Energy Commission funding, WESTCARB assessed opportunities for CO_2 utilization (also known as CO_2 beneficial use) to assist California in meeting its 2020 and 2050 greenhouse gas (GHG) emissions reductions goals. A research roadmap of utilization technologies was developed using technology readiness criteria and factors specific to California. Based on these findings, the Energy Commission subsequently issued a solicitation for research in the most promising areas.

The roadmap ranked technologies based on their potential to impact GHG emissions in the context of California's carbon and energy goals and on technology readiness. Highest rankings went to biological conversions, treatment of displaced aquifer fluids, building materials, working fluids for energy storage, and enhanced oil and gas recovery (EOR and EGR) applications. Of these, EOR is the only technology considered to be mature. All the other technology areas were recommended as potential areas for further research.

This study concluded that no systematic set of data or methodologies currently exist to compare overall impacts of various technologies. Each technology has advantages and disadvantages, but their relative importance can only be qualitatively inferred. In addition, while only a few technologies are likely to contribute meaningful reductions in CO_2 emissions, inclusion of these technologies in CCS projects may produce local economic, political, and social benefits unattainable by a stand-alone geologic storage project.

CO_2 Point Source Database

As one of DOE's seven Regional Carbon Sequestration Partnerships (RCSP), WESTCARB contributed to the carbon storage atlases and databases published or maintained by National Energy Technology Laboratory (NETL) for the United States and Canada. The atlases have been published biennially since 2006. Additionally, the National Carbon Sequestration Database and Geographic Information System (NATCARB) provide emissions point source data and geologic storage data that can be downloaded and utilized by stakeholders or researchers through several interactive web applications.

Phase III updates included the addition of about 250 emissions point sources, bringing the total facility count to over 500 in the WESTCARB region. These additions include some new facility types but primarily reflect increased facility populations in the reference databases.

In WESTCARB's Atlas IV, CO2 emissions from large facilities was estimated at 340 million metric tons (Mt) per year. Electric power plants and cogeneration units are the predominant source types in the WESTCARB region, producing about 70 percent of the point source CO_2 emissions. They represent the largest point source category in each WESTCARB state or province, with the exception of Alaska and British Columbia, where petroleum and natural gas facilities (production, processing, and transportation) are the greatest industrial contributors to CO_2 emissions.

The Potential for CCS for Natural Gas Power Plants

WESTCARB conducted an engineering-economic assessment of applying CCS to natural gas combined cycle (NGCC) plants; additionally, WESTCARB developed a proposed scope of work and preliminary feasibility study for an NGCC-CCS pilot project in California. The study found that the more commercially mature, solvent-based post-combustion capture processes were less expensive than pre-combustion fuel reforming; they also offered more data for cost-assessment than nascent oxy-combustion, membrane, and other novel capture technologies. Design considerations for California locations include high summer temperatures, the limited availability of water, and the requirement for dry cooling for any new plants built in California. Findings were inconclusive regarding the value of flue gas recycle as a means of reducing CO_2 capture system levelized costs, although other studies have suggested this approach holds promise. In particular, the study notes that the simplest approach, involving use of a direct contact cooler for the recycled flue gas, may not provide the best performance results.

The total engineering, procurement, and construction (EPC) cost for installing CCS at a new build, nominal 600 MW NGCC plant in California is about $900 million, which not only includes the CO_2 capture and compression systems, but also the CO_2 pipeline and injection systems. The within-the-plant portion of this cost appears higher than that for studies at other U.S. locations due to the requirement for dry cooling and higher labor costs. The study also employed an EPC contracting structure instead of an engineering, procurement, and construction management (EPCM) contracting structure, as it was believed to be more representative of commercial practices. This approach tends to boost costs relative to studies using an EPCM method (but in the real world, would reduce risk), making inter-study comparisons more difficult. The levelized cost of electricity (LCOE) for the new-build NGCC facility was estimated to increase by approximately 35 percent due to the addition of the CCS system. Activities which can be expected to reduce capital costs in the future include:

- Focused research to improve capture technology cost and efficiency
- Growing an EPC knowledge base. A reduction in future capital costs by 30 percent would result in a LCOE decrease of approximately 25 percent.

Issues with Implementation of CCUS

During Phase III, WESTCARB produced two reports examining the status of CCUS technology in the WESTCARB region and assessing factors affecting successful commercialization in California. The *Assessment of the Barriers and Value of Applying CO_2 Sequestration in California* report found that CCUS is recognized as a greenhouse gas reduction strategy within California's climate change policy and globally. California is unique in the WESTCARB region and at the forefront nationally with the enactment of laws that require GHG emissions reductions in accordance with the timing and volumes recommended by the Intergovernmental Panel on Climate Change. WESTCARB research and expertise have supported California agencies by providing technical and nontechnical assessments of CCUS as an option to meet mandated GHG emissions reductions. Additionally, WESTCARB has provided recommendations for regulatory and policy actions facilitating development of commercial-scale CCUS projects on power and industrial emission sources.

The report concluded that California would lower its GHG emissions risk by accelerating policy, regulatory, and applied RD&D actions that contribute to the adoption of CCUS technologies as GHG emissions reduction options. It also indicated that such actions would need to be taken in a timely manner to meet the State's 2050 GHG reduction goals, given the long lead times for CCUS project development and the need to incorporate CCUS into California's evolving energy infrastructure and policy constructs.

WESTCARB also produced a Regional Technology Implementation Plan, which examined the status of CCUS implementation in the WESTCARB region. The report noted that most of the WESTCARB region has substantial geologic storage potential. Studies indicate generally short distances between large stationary CO_2 sources and geologic sinks. Critical factors to enabling deployment lie in the policy, economic, and social realms. Three significant challenges include: (1) lack of national climate change legislation to serve as a driver, (2) lack of a clear regulatory pathway for CCUS where climate change legislation exists, (3) high cost of deployment, and (4) low price of tradable CO_2 emission allowances.

Benefits

Results from WESTCARB's Phase III indicate that CCUS is a technically feasible solution that could contribute major GHG reductions from stationary CO_2 emissions sources. Overall, the WESTCARB region has substantial geologic storage potential, and studies indicate generally close proximity between large stationary CO_2 sources and geologic formations conducive to secure storage.

In California, adoption of CCUS could be furthered by accelerating policy, regulatory, and practical actions in a timely manner to help meet the State's ambitious GHG reduction goals. Opportunities for CO_2 utilization in applications such as biological conversions, building materials, working fluids for energy storage, and enhanced oil and gas recovery should be supported by the development of a systematic set of data or methodologies. This would enable meaningful comparison of the overall feasibility of CO_2 reduction by each technology, and to facilitate their acceptance as compliance options for covered entities under California's cap-and-trade program.

Application of CCS to California's NGCC plants is not required to meet current state or federal laws and appears uncompetitive compared to other options for generating tradable emission allowances at current market prices. However, this situation may change as the number of emission allowances decreases over time and the costs of CO_2 capture decline as the technologies improve and mature. Support for NGCC-CCS development through policy, funding, and pilot projects stands to benefit California by ensuring a robust portfolio of GHG reduction options.

CHAPTER 1: Studies Impacting Geologic Carbon Sequestration Potential in California

Prior WESTCARB studies by the California Geological Survey provided an initial screening of the geologic sequestration potential of California's onshore sedimentary basins and a regional evaluation of sequestration potential in the southern Sacramento Basin. The three studiesundertaken in Phase III expanded upon these earlier studies by addressing: the potential for geologic sequestration in California's offshore sedimentary basins; the impacts of the U. S. Environmental Protection Agency's (USEPA) underground drinking water standard of 10,000 mg/l total dissolved solids on potential sequestration in selected California basins; and the impact of compartmentalization within existing oil and gas fields on carbon sequestration potential within depleted or abandoned hydrocarbon reservoirs(Downey and Clinkenbeard, *Studies Impacting Geologic Carbon Sequestration Potential in California*). Research also investigated how to improve the future formulation of seismic hazards regulations for CO_2 storage projects in California.

1.1 California's Offshore Basins

An investigation was undertaken to characterize California's offshore basins in a manner similar to that used for WESTCARB's Phase I evaluation of onshore basins. However, a lack of available information on offshore geology prevented mapping at the level of detail needed to estimate potential CO_2 storage resource within the offshore saline formations. Consequently, storage resource was calculated only for known developed and undeveloped offshore oil and gas fields. Consistent with the Phase I evaluation, only conventional sandstone reservoirs in offshore basins were considered.

Twenty sedimentary basins lie offshore, or extend offshore, from mainland California, but only three of these basins—the Ventura, Los Angeles, and Santa Maria Basins—contain known oil and gas fields. However, many of the known offshore oil reservoirs in the Ventura and Santa Maria Basins consist of fractured shales of the Monterey Formation, which are considered unsuitable for sequestration due to the difficulty of characterizing fractured reservoirs and the evidence for leakage via sea floor seeps associated with many of these reservoirs.

A total of 30 offshore oil and gas fields in conventional sandstone reservoirs have been discovered within the Ventura and Los Angeles Basins. Of these, 24 fields are producing or have been depleted. These fields are likely the most promising options for offshore carbon sequestration based on the reliability of existing production figures and reserve estimates. Based on these data, they have a total estimated CO_2 storage resource of 236 Mt. An additional six oilfields have been discovered in federal offshore waters but remain undeveloped. Thus, their hydrocarbon reserve estimates remain highly speculative. However, based on available data, these fields contain an additional CO_2 storage resource of approximately 3.0 Mt.

1.2 Formation Water Salinity

Data on formation water salinity in California sedimentary basins are generally unavailable. Where they exist, they are typically proprietary files of the oil and gas companies that have explored for or developed gas and oil reserves in the basins. Thus, it is not possible to perform a statewide evaluation of salinities using the total dissolved solids limit of 10,000 mg/L set by USEPA's underground drinking water standard. However, salinity may be estimated from some types of geophysical oil and gas well logs.

In the Mokelumne River, Starkey, and Winters Formations of the Sacramento Basin, salinities were estimated from spontaneous potential logs to identify areas of low salinity (less than 10,000 mg/L total dissolved solids). The Mokelumne River, Starkey, and Winters Formations of the southern Sacramento Basin all contain significant thicknesses of porous and permeable sandstone that may be suitable for CO_2 storage within existing or abandoned gas and oil fields or saline formations. Previously, CGS identified potential storage resource within these formations based only on criteria for minimum depth (3400 ft or 1,133 m) and seal thickness (100 ft or 33 m).

Consideration of formation water salinity eliminates those areas that contain potential underground drinking water sources (less than 10,000 mg/L TDS). Compared to previous assessments, this resulted in a reduction of the area underlain by Mokelumne River Formation sandstone deemed suitable for CO_2 storage. Relatively fresh waters were identified in the Mokelumne River Formation sandstones within a limited area, located in the southwest portion of the Sacramento Basin, near known Mokelumne River Formation surface outcrops. With no geochemical analyses of formation waters available for verification, recharge of the subsurface via these surface sandstone exposures is assumed to be the likely cause of this area of lower salinity. There is no conclusive evidence of low salinity water within sandstones of the Starkey or Winters Formations, which are not exposed at the surface anywhere in the Sacramento Basin.

Accordingly, a revision of the Mokelumne River Formation storage resource potential was made. In this study, the areas assigned are 935 square miles (2,422 square kilometers) underlain by the Mokelumne River, 920 square miles (2,382 square kilometers) by the Starkey, and 1524 square miles (3,947 square kilometers) by the Winters Formation. The revised storage resource estimate for the three formations meeting depth, seal, and water salinity criteria is 3.2 to 13.0 billion Mt of CO_2.

1.3 Compartmentalization

In many California oil and gas fields, hydrocarbons are not produced from a single large reservoir, but rather from multiple compartments or "pools" of varying sizes representing separate trapped hydrocarbon accumulations. As a result, the total storage resource calculated from historic oil and gas production for one field may actually be split among a few, or many, smaller pools.

Variation in pool size will potentially impact the economics and practicality of sequestration in depleted oil and gas fields. To evaluate the amount of compartmentalization that might occur, the pool size distribution for three typical gas fields in the southern Sacramento Basin—Bunker, Millar, and Conway Ranch—was evaluated.

The CO_2 storage estimates determined for the known natural gas pools within the Bunker, Millar, and Conway Ranch gas fields suggest that the potential for long-term CO_2 storage is limited within single pools in these or similar fields of the southern Sacramento Basin. Most pools within Mokelumne River, Starkey, and Winters Formations have CO_2 storage insufficient to store even a single year's worth of a typical industrial facility or power plant's CO_2 emissions. Even the largest pools in each field exhibit limited storage capacities. These range from only 1.7 Mt for the Conway Ranch Field to 6.6 Mt for the Bunker Field. For a source emitting 2.0 Mt of CO_2 per year, the largest pool at Conway Ranch Field could store less than a year's worth of emissions, while Bunker Field's largest pool could store slightly more than three years' worth.

Multiple pool strategies are also likely to fall short of meeting the lifetime needs of a typical emissions source. Only 14 out of 313 pools have estimated resource of more than 0.5 Mt CO_2.

In total, Bunker Field has 15.2 Mt of storage resource in 5 pools, Millar Field has 7.0 Mt in 7 pools, and Conway Ranch Field has 2.0 Mt in 2 pools. With the possible exception of Bunker Field, these fields have much less than the 15 to 30 Mt necessary to meet the lifetime needs of a large- to medium-sized emissions source. The addition of smaller pools to increase storage in each field does not significantly increase the estimates. Even if it were economically viable and technically feasible to access the many pools within each field, maximum field storage increases to only 17.9 Mt (Bunker Field), 17.8 Mt (Millar Field), and 6.8 Mt (Conway Ranch Field).

Although the Bunker, Millar, and Conway Ranch Fields are considered suitable analogs for most gas fields in the Sacramento Basin, larger fields (from a production standpoint) do exist within the Basin and may offer better opportunities for CO_2 storage. Although not part of this study, further increases of CO_2 storage volume within a specific natural gas field could likely be obtained by considering the non-hydrocarbon-bearing parts of these sandstone formations, as well as overlying and underlying sandstone bodies.

While this study is limited to fields and formations in the Sacramento Basin, fields in other California basins with similar settings and geologic and tectonic histories could exhibit similar degrees of compartmentalization and limitation of potential reservoir capacity.

CHAPTER 2:
CO_2 Storage Site Studies

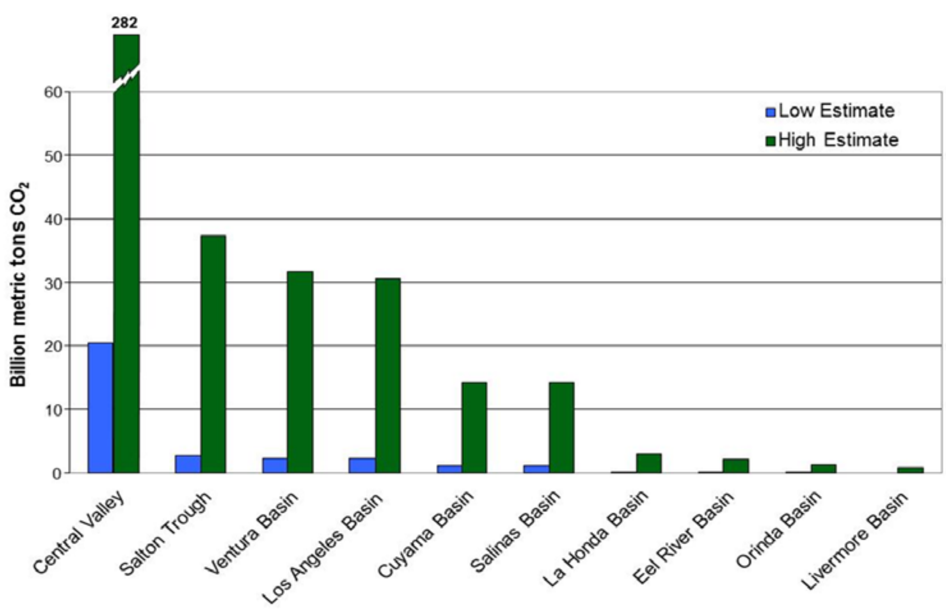
To prepare for potential pilot-scale injections and a large-volume storage demonstration, WESTCARB performed site characterization work in California in collaboration with the California Geological Survey and various industry partners interested in CCS development. The results from these endeavors were used to select specific sites for more detailed studies.

WESTCARB developed a set of geologic, geographic, and nontechnical and logistical criteria to rank potential sites for drilling a characterization well. In addition, each site was evaluated to assure that the well plan would be able to meet the scientific objectives of the characterization project.

2.1 CO_2 Storage Potential in California's Central Valley

It was determined that the characterization well should lie within the Central Valley of California, which is one of the most promising CO_2 storage opportunities in WESTCARB's territory (Figure 2). The Central Valley is a large depositional basin that has received sediments almost continuously since the late Jurassic and contains as much as 40,000 feet (13,333 m) of mostly marine, sedimentary rocks (Magoon and Valin, 1995).

Figure 2: Estimates of Storage Resource in California's Major Sedimentary Basins

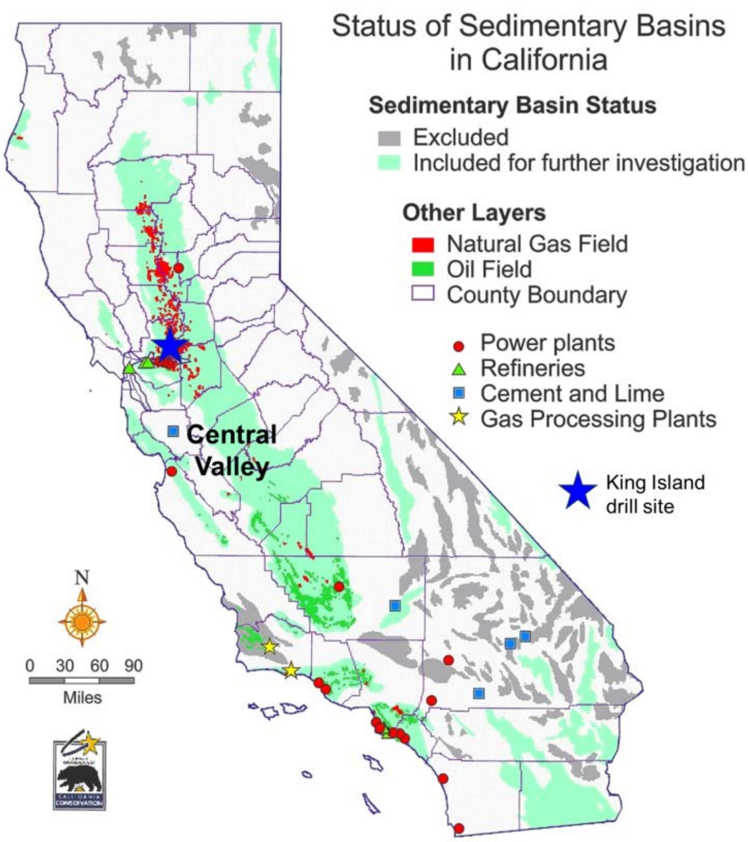


Source: Cameron and Downey

The Central Valley is divided into the Sacramento Basin in the north and the San Joaquin Basin to the south by the buried Stockton Arch, south of the City of Stockton. The southern portion of the Sacramento Basin has some of California's largest natural gas fields. Now largely depleted, these fields present opportunities for CO_2 sequestration. Oil fields in the southern San Joaquin Basin could provide opportunities for CO_2-EOR (Figure 3). Both basins have large storage potential in non-hydrocarbon-bearing saline formations.

Extensive geologic and well log data exist for the hydrocarbon-bearing strata from oil and gas exploration, but data are sparse for deeper saline formations and overlying cap rocks. Data for these potential reservoir and seal formations are needed to enable more refined estimation of storage capacity.

Figure 2: Map of California Showing Major Sedimentary Basins, Oil and Gas Fields, and the King Island Drill Site



Four Central Valley sites were considered: King Island, Thornton, Montezuma Hills, and Kimberlina. Kimberlina lies within the San Joaquin Basin. King Island, Thornton, and Montezuma Hills lie within the southern Sacramento Basin. All sites met the geologic and geographic criteria; however, the King Island site met the scientific objectives better than the other three sites. Furthermore, King Island was the only site that completely fulfilled the nontechnical and logistical criteria related to liability, permitting, site access, and other non-technical factors necessary to assure successful completion of the project. It was these nontechnical factors that eliminated the other sites from further consideration, although the Kimberlina site was ranked a close second and was chosen as a back-up.

2.2 Geologic Characterization Well at King Island

In the December 2011, WESTCARB drilled the Citizen Green stratigraphic well on King Island in the southern Sacramento Basin to characterize CO_2 storage targets in a depleted natural gas reservoir and underlying saline formations. An existing inactive well was used for the first 700 feet (233 m) of depth, before drilling a deviated well to access the target formations (Figure 4).

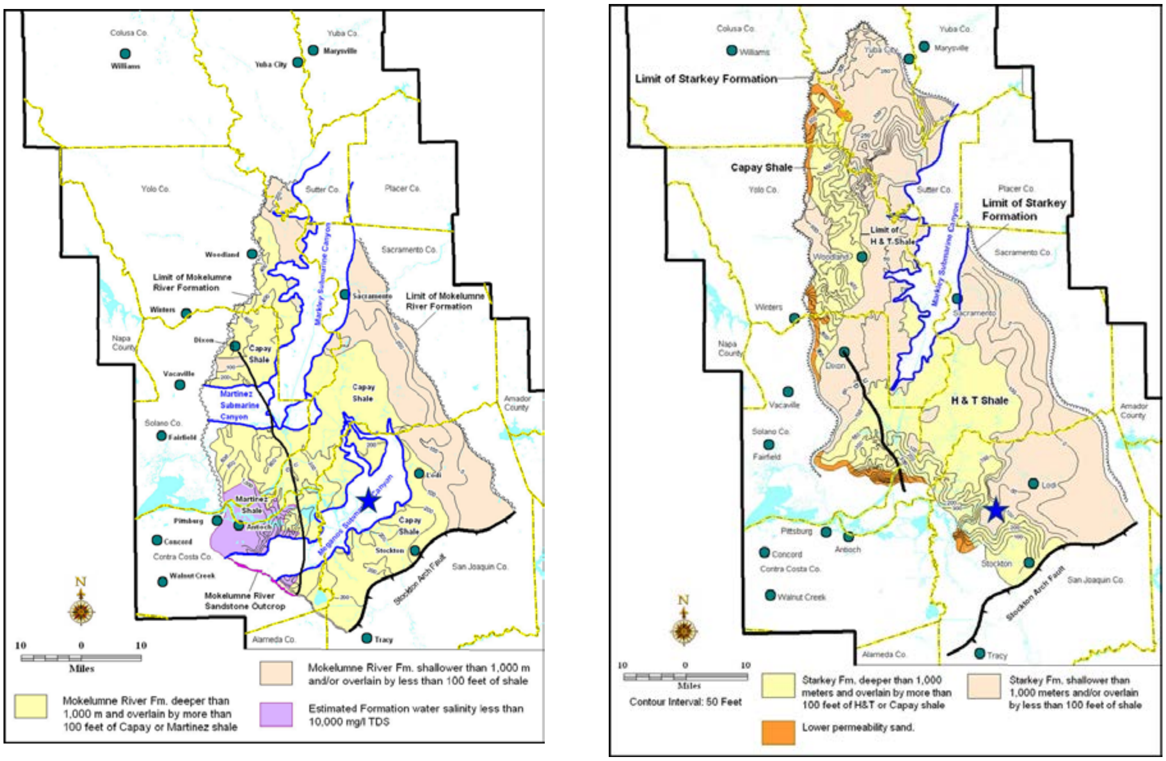
Figure 3: Drill Site on King Island with Workover Rig

At King Island, the Mokelumne River Formation is gas-bearing in a pinnacle in the Meganos Gorge. The Capay shale overlies the pinnacle. The Domengine and Starkey Formations are not intruded by the gorge. The Citizen Green Well penetrated these potential storage reservoir formations and overlying shale seals (Figure 4).

The Citizen Green Well was drilled directionally to a vertical depth of 6920 feet (2110 meters). Core samples and logging data were analyzed at Lawrence Berkeley National Laboratory (LBNL) and shared with researchers at two of DOE's Frontier Energy Research Centers. The project included well-logging and recovering rock and fluid samples.

The potential storage formations penetrated by the Citizen Green Well include the Domengine, Mokelumne, and Starkey Formations. The Domengine has high permeabilities (greater than 3 Darcys) as observed on Combinable Magnetic Resonance (CMR) log data. It is unconsolidated, but it is questionable whether the overlying shales of the Nortonville are suitable sealing units.

Figure 4: Mokelumne River and Starkey Sandstones[1]



The upper Mokelumne, with a thickness of 1500 feet (460 meters) has high permeability (greater than 1 Darcy) based on CMR and is unconsolidated sand. With depth, the sand loses permeability and becomes consolidated below 5500 feet (1680 meters). The Mokelumne is gas-bearing, suggesting integrity of the overlying sealing shale, the Capay Formation. The Starkey had much lower permeability overall, but several higher permeability sand lenses showed CMR permeability of about 100 millidarcies.

To test the potential of seismic methods for monitoring subsurface CO_2 behavior in these sandstones, LBNL's Split Hopkinson Resonant Bar (Short-core Resonant Bar) test setup (Figure 6) was used to measure kilohertz-range seismic velocities and attenuations of a core sample that was flooded with supercritical CO_2.

To avoid issues with drilling mud contamination and obtain a large enough sample, a 6-inch (15.2 cm) long, 1.5-inch (3.8 cm) diameter core of the Domengine was obtained from a nearby mine. The sample had greater than 2-3 Darcy permeability and 30 percent porosity. Test conditions replicated the in-situ temperature and pressure estimated for the depth of the Domengine at the King Island site. The core was filled with a 10,000 mg/L solution of sodium chloride, replicating the in-situ brine salinity. Supercritical CO_2 was then injected at one end of

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[1] Reference: Downey, Cameron, John Clinkenbeard, (California Geological Survey) 2011, Studies Related to Geologic Carbon Sequestration Potential in California, California Energy Commission,

the core and seismic properties were measured as the CO_2 displaced the brine through the length of the core. Results show that seismic velocities decrease as the CO_2 displaces the brine; breakthrough of CO_2 occurred after only 0.19 pore volumes of CO_2 were injected (Figure 7). A pore volume is the amount of fluid injection required to fill all of the core pore space. Seismic attenuation (scattering or decay of the waves) shows a complex pattern, increasing and then decreasing, and finally increasing substantially. To assess how well the rock holds the CO_2 once it occupies the rock pore space, a process caused residual trapping, the core was continuously flushed with the saline solution. Residual trapping is very high, indicated by the over 50 pore volumes of brine required to flush all of the CO_2 back out of the core (Figure 8).

Figure 5: Split Hopkinson Resonant Bar Test Setup

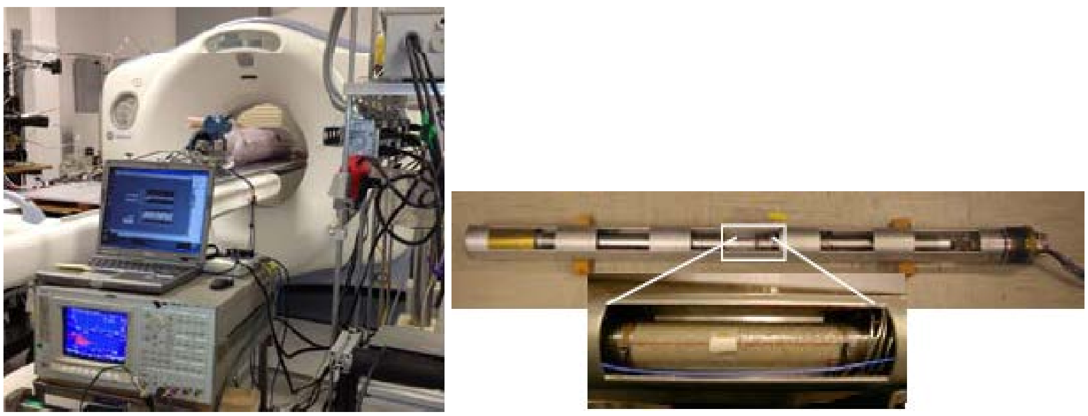


Figure 6: Seismic Velocities and Seismic Attenuation for Domengine Core Sample

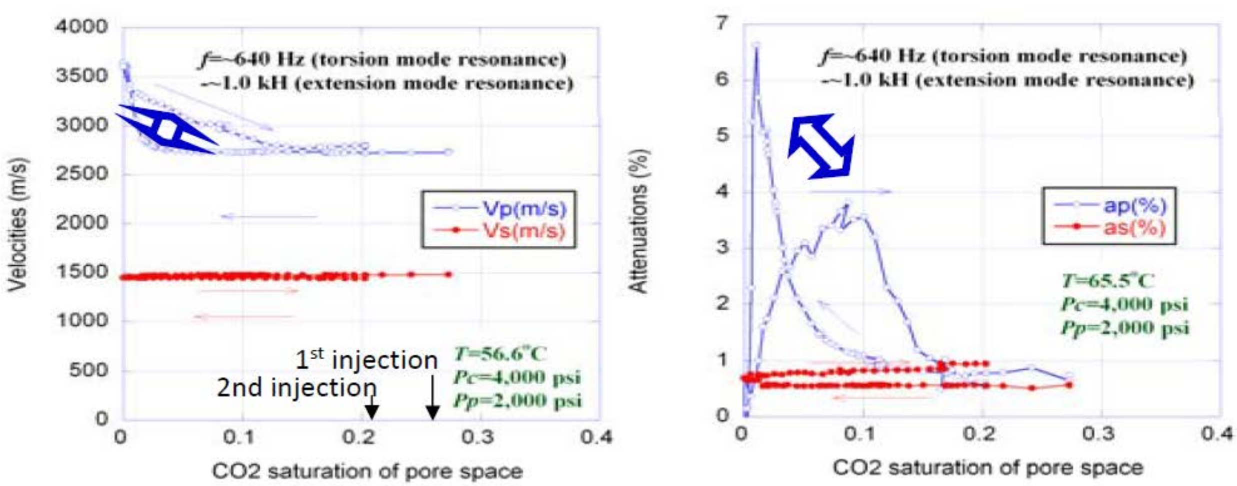


Figure 7: Residual Trapping for Domengine Core Sample

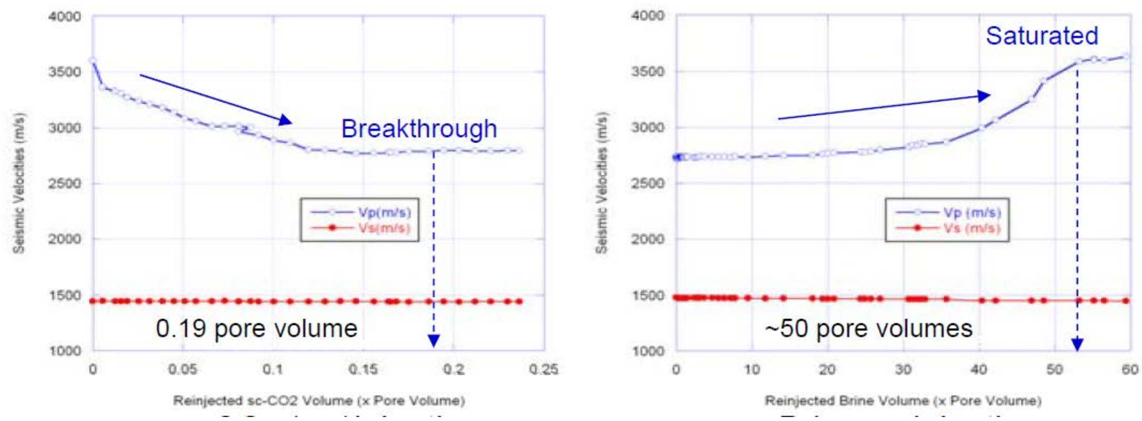


Figure 8: Stratigraphic Column Showing Estimated Depths of Sandstones, Shales, and Core Intervals for the Citizen Green Well

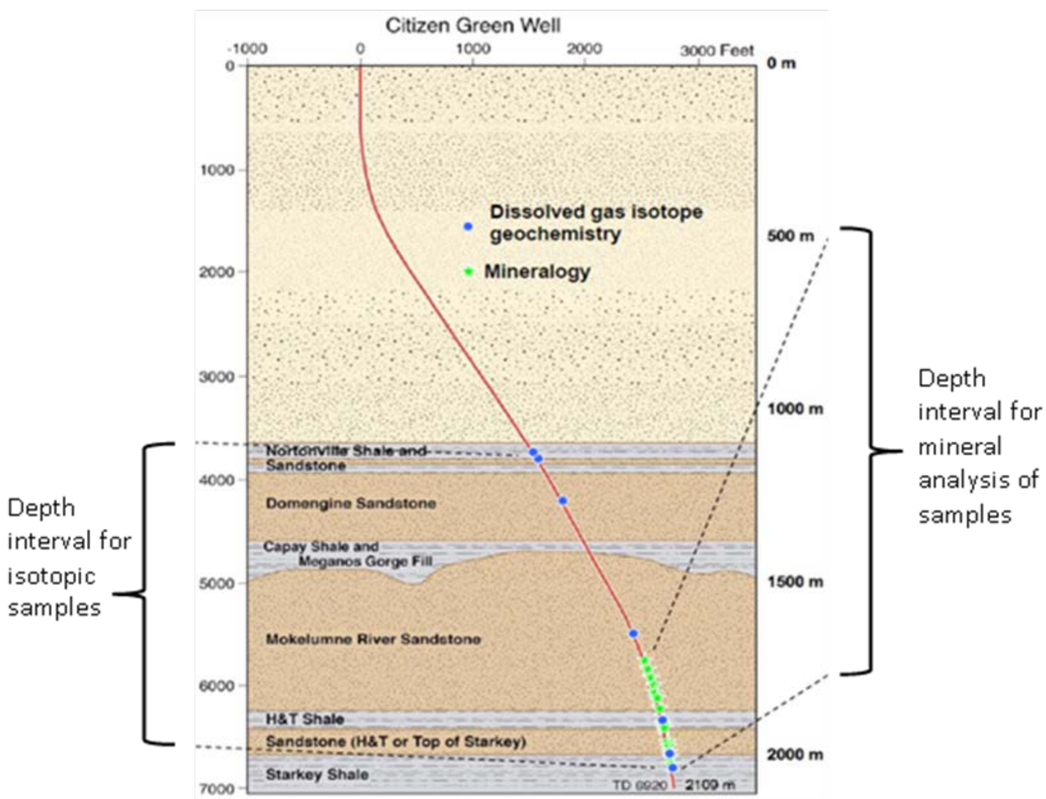


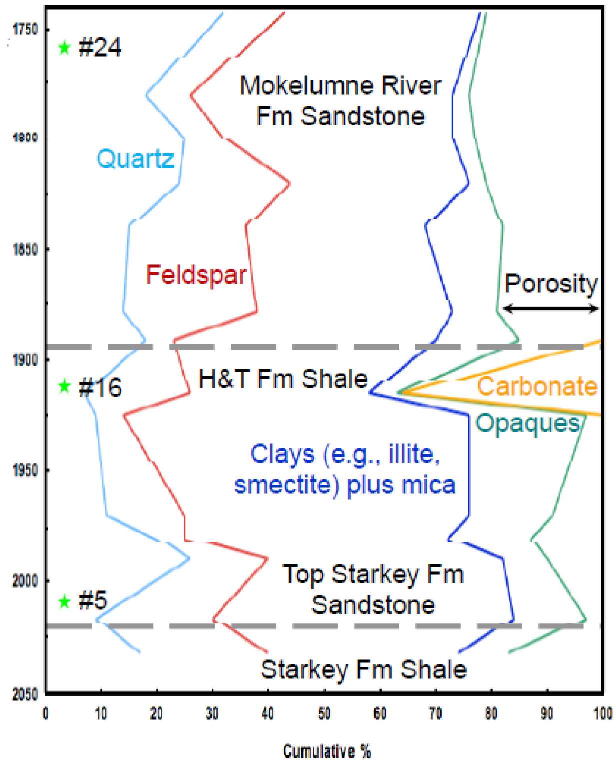
Figure 10: Mineral Results from Citizen Core Samples

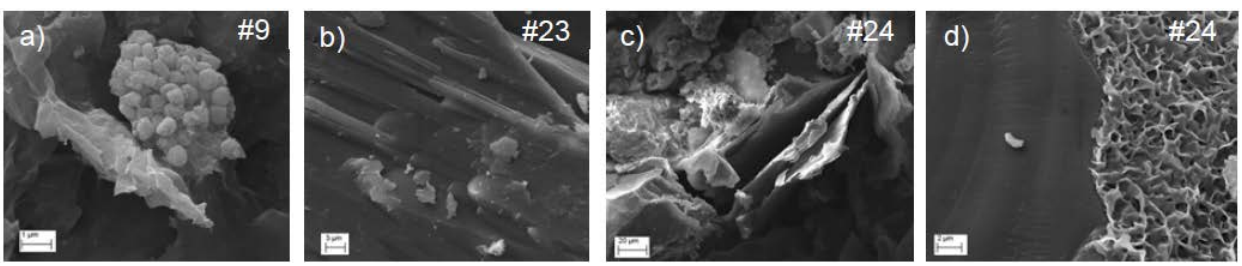
				Flow Properties		Quantitative XRPD (Rietveld) [weight %] (s.d. relative to the last significant digit)								
Sample ID	Wireline depth [ft]	TVD [ft]	Formation	Porosity (He) [%]	Permeability (gas) [mD]	Quartz	K-feldspar	Plagioclase (more sodic: Andesine)	Plagioclase (more calcic: Labradorite)	Kaolinite	Chlorite	Pyrite	Amphybole	Detrital mica
#8	7136	6492.3	Top Starkey Sand	31.4	432.6	42.8(11)	8.7(9)	39.6(15)	n.d.	1.4(4)	4.7(5)	<1	<1	2.4(6)
#9	7104	6460.9	Top Starkey Sand	27.6	114.3	39.9(4)	6.5(2)	27.3(6)	n.d.	5.7(4)	8.5(5)	1.2(1)	n.d.	9.5(6)
#15	6936	6296.8	H&T Shale (sand stringer)	34.2	299.9	44.1(4)	16.6(3)	30.4(4)	n.d.	4.2(3)	4.5(4)	n.d.	n.d.	<1
#21	6598	5970.1	Mokelumne River Fm.	31.3	135.5	33.9(11)	22.0(11)	34.5(15)	n.d.	3.6(4)	5.4(6)	<1	<1	<1
#23	6466	5843.1	Mokelumne River Fm.	31.3	71.9	36.3(18)	12.6(3)	<1	36.6(6)	2.7(3)	5.4(4)	<1	<1	5.0(7)
#24	6400	5780.1	Mokelumne River Fm.	33	367.1	40.3(5)	17.1(6)	3.6(8)	29.2(6)	5.2(5)	4.0(6)	n.d.	<1	<1
Shale baffle	5249	4725.2	Mokelumne River Fm.	NA	NA	17.0(3)	32.7(6)	6.5(2)	n.d.	34.9(6)	n.d.	n.d.	n.d.	8.4(3)
Top reservoir	5247	4723.5	Mokelumne River Fm.	NA	NA	27.8(5)	16.2(4)	34.0(10)	n.d.	3.6(4)	17.0(5)	n.d.	n.d.	<1

The mineral compositions of the Citizen Green cores were determined through x-ray diffraction analysis and point-counting of thin sections made from sidewall core samples. The depth locations of the samples are shown in Figure 8. The mineral results are shown in Figure 10. These sandstones are composed primarily of quartz and feldspars, with a few percent clays (kaolinite, chlorite) and traces of pyrite, amphibole, and mica. Of the minerals present, quartz, K-feldspar, and sodic-Plagioclase are least reactive; calcic-Plagioclase is more reactive.

The mineral composition of the formations is important for determining the long-term fate of stored CO_2. Over time, CO_2 dissolves certain minerals and forms new minerals. The CO_2 is thereby permanently stored through this mineralization process. In general, formations with the greatest amount of reactive minerals have the best storage resource potential.

Figure 11: Mineralogy from Thin-Section Point-Counting of Sidewall Cores



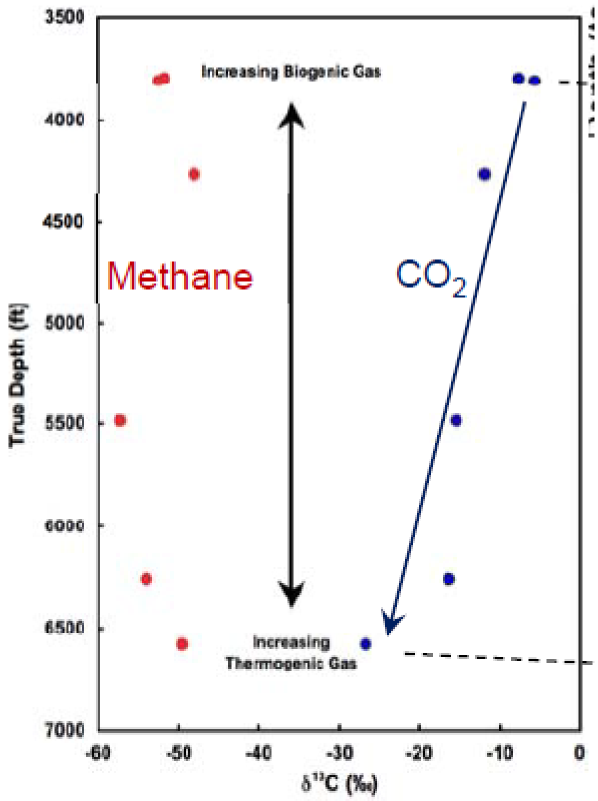


Scanning Electron Microscope images of accessory minerals in Citizen Green storage formation sands. Numbers correspond to samples in Figure 10. a) framboidal pyrite; b) amphibole; c) mica; d) smectite.

The upper Mokelumne is less reactive, but the significant percentages of calcic-Plagioclase in the lower Mokelumne and Starkey give these formations high mineralization trapping potential, making them potentially attractive resources for CO_2 storage.

Carbon isotopic signatures of gas samples collected by degassing core samples provide information about the sources of the methane natural gas and natural CO_2. Carbon isotopic signatures (expressed as $\delta^{13}C$) of the methane at all depths suggest an origin from a mix of thermogenic and biological processes. The $\delta^{13}C$ of the natural dissolved CO_2 in the cores decreases with depth, indicating that a shift from CO_2 produced mostly as a byproduct of biologic methanogenesis in the Nortonville and Domengine to CO_2 from abiotic or thermal methane production in the Mokelumne and Starkey (Figure 12).

Figure 12: Carbon Isotopic Analysis



Simulations of commercial-scale CO_2 injection were performed for the King Island site. An injection rate of 1.0 Mt per year for a period of four years into the lower half of the Mokelumne Formation was simulated. The model captures the effects of the higher permeability in the upper section and the effects of the lower permeability, finer-grained sands in the lower section. These permeability differences are apparent on the well logging results, which show that while porosity remains relatively constant with depth, permeability decreases by about two orders of magnitude with increasing depth (Figure 13).

Figure 13: Well Log Showing Porosity and Permeability

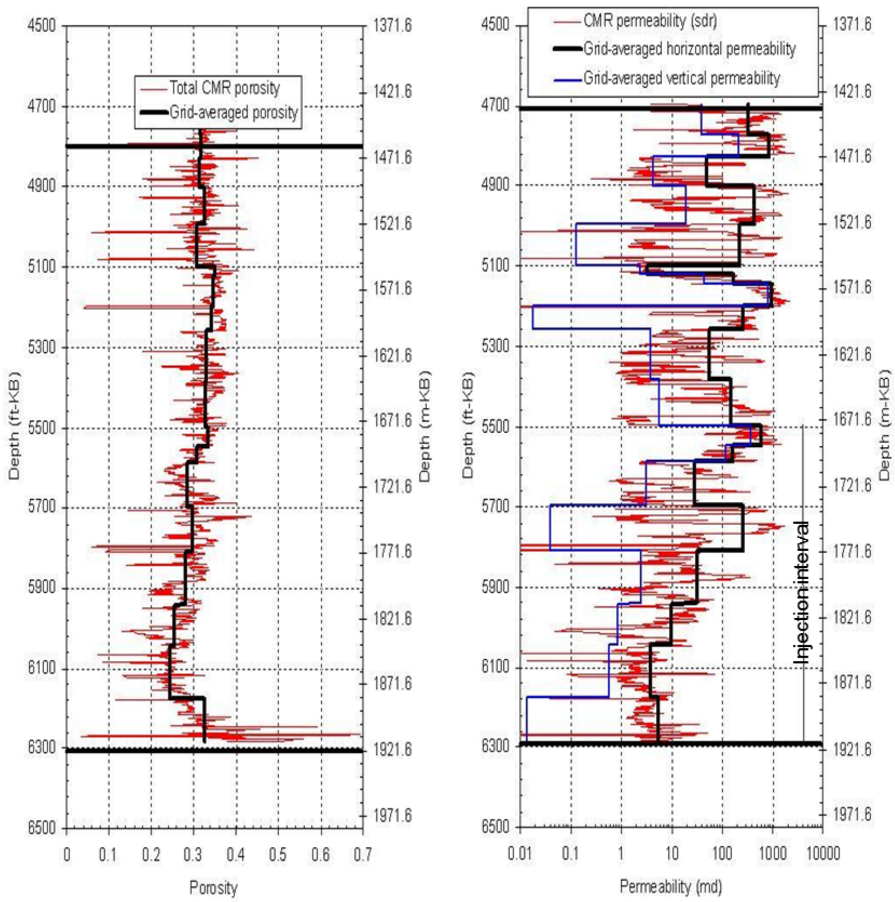
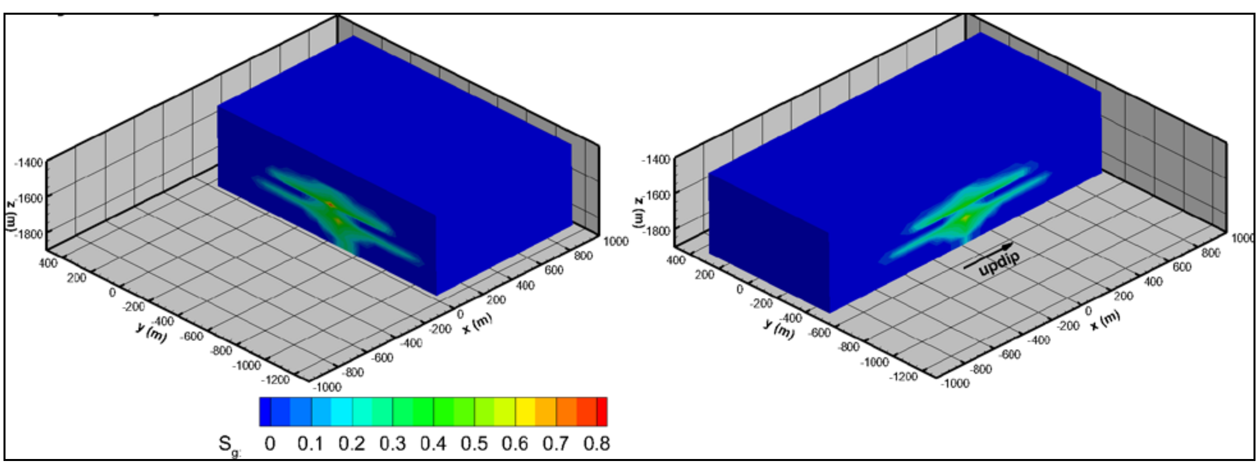


Figure 14: Simulation Results of Mokelumne Formation CO2 Injection Showing CO2 Saturation Levels Away From the Well at the End of the Four Year Injection Period



Results showed strong lateral flow of the CO_2 in the high permeability zones with a slight up-dip migration. The lower permeability units act as baffles, greatly reducing any tendency for vertical, upward migration of the CO_2. Measuring out from the well, at the end of the injection simulation period, the injected CO_2 extends out about three fourths of a mile, but remains more than 300 feet (100 m) below the top of the Mokelumne Formation reservoir (Figure 14).

2.3 Site Characterization at Kimberlina

The Kimberlina Power Plant site lies in the San Joaquin Valley near Bakersfield. In conjunction with Clean Energy Systems, WESTCARB undertook a feasibility and risk assessment study of the site for a large-volume CO_2 capture and storage demonstration. Kimberlina lies within California's prolific oil-bearing region; thus, significant numbers of wells surrounding the site provided an extensive dataset to construct a geologic model of the site. Simulations were done to assess the potential of the site for a large-scale injection of 1 million tons over four years from a proposed 50 MW oxy-combustion power plant to be built at the site.

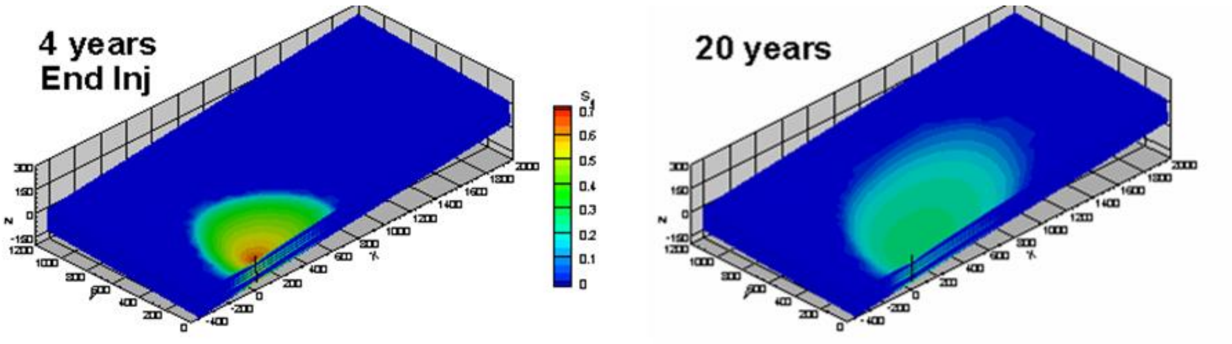
A geologic model centered at Kimberlina with surface dimensions of 50 kilometers x 50 kilometers was constructed to assess stratigraphic and structural features affecting selection of formations for saline storage. Over two hundred well-logs from surrounding oil field were used to create the model. The Vedder Formation was selected as the storage formation.

From this large model, a 30-layer reservoir simulation model for the Vedder was created in order to capture the effects of the variable porosity and permeability within this sandstone formation. The model grid covers an area of 225 km^2 of the Vedder Formation, which is 160 meter thick and dips 7 degrees to the southwest. The simulation covered a four-year period of injection from a 50 MW power plant at the Kimberlina site, and then followed the subsequent migration of the CO_2 for hundreds of years after injection stopped.

Simulation results show that the injected CO_2 is effectively immobilized 20 years after injection ceases (Figure 15). At that time, about 35 percent of the CO_2 is dissolved in the saline formation water, 60 percent is immobile gas trapped in the pore spaces of the rock, and less than 5 percent is mobile gas able to potentially migrate within any fluid moving within the rock. The CO_2 extends in a roughly elliptical pattern, with a long axis of about 1500 meters and a short axis of 900 meters, asymmetrically about the injection well, extending 1300 meters toward the northeast and 200 meters toward the southwest, reflecting the slight slope of the Vedder up toward the northeast and the regional hydrologic gradients.

The pressure increase from CO_2 injection, however, extends beyond the footprint, reaching the model boundaries eight kilometers away from the injection well. The amount of increase becomes smaller rapidly with distance and time. The pressure anomaly is less than 0.3 bars beyond five kilometers by the end of the injection period; it is less than 0.4 bars everywhere three years after injection ends. Sensitivity studies show that model predictions change with permeability, permeability anisotropy, characteristic-curve parameters, and in situ conditions for temperature and salinity.

Figure 15: Simulation of a 1.0 Million Ton Injection of CO2 into the Vedder Formation



To further evaluate the Kimberlina site as a candidate for a large-scale demonstration, WESTCARB conducted a project risk assessment involving experts, including representatives from the California Energy Commission, the WESTCARB management and technical teams, experts from WESTCARB member organizations, and Schlumberger Carbon Services. “FEPs” (Features, Events, and Processes) were rated on 1-through-5 scales, in terms of the Likelihood (L) and Severity (S) of risks posed to defined project values. Results were processed, evaluated, and compiled into a database and document to support a Risk Management Report.

In a parallel effort, an initial risk assessment using the Certification Framework (CF), developed by the Carbon Capture Project, was completed for the Kimberlina site (Oldenburg, Nico, and Bryant, *Case Studies of the Application of the Certification Framework to Two Geologic Carbon Sequestration Sites*). The CF is focused primarily on the risk of leakage, which is a major technical risk. The CF analysis defines a storage region and then evaluates the potential for migration via wells or faults to “compartments” and the potential for impacts on these compartments. The CF considers four “compartments”: hydrocarbon and mineral resources; underground sources of drinking water; health, safety and environment; and atmosphere or emission credits. Though the CF normally considers only CO_2 migration risk, for this assessment, brine migration risk was also considered. The initial CF analysis used data already available on surface characteristics, subsurface geology, wells, hydrology, groundwater salinity, and faults. It relied basically on much of the same information used to construct the geologic model and on the simulation results described above.

For purposes of the CF, the storage region was defined as the Vedder Formation, extending six miles (10 km) from the injection well. The analysis showed no known wells penetrating the Vedder within 1.5 miles (2.5 km) of the predicted CO_2 migration extent. Detailed information on faults at the Kimberlina site was not available, so information from oil fields in the area was used in an analysis yielding a probability distribution that was then used to populate the simulation model. The probability that any migrating CO_2 would reach a fault that offsets the shale caprock (for example , leakage above the seal) is approximately three percent. However, evidence from known faults in the area indicates that most such faults have relatively low permeability and are therefore unlikely to be flow paths for migrating fluids. In summary, while the CF analysis showed that it is very likely that the pressure pulse will extend to any wells and faults that penetrate to the depth of the Vedder, the CO_2 is unlikely to migrate upward to impact compartments.

2.4 Seismic Hazards Risk Assessment

Injecting fluids into the subsurface causes a rise in the pore pressure of rock formations, which can result in small seismic events. The potential for these events should be assessed during site selection and in the design, operation, and monitoring of CO_2 storage projects. The vast majority of seismic events from fluid injection are not recognized as “earthquakes” because they do not release enough energy to be felt at the surface or cause damage. In fact, there is an entire technology associated with the use of these “microseismic events,” as a useful tool for monitoring the movement of fluids in the subsurface.

Seismic events due to subsurface fluid injection that are large enough to be felt are infrequent. There have been instances in which engineered geothermal operations have resulted in ground motion that was felt by nearby communities. More recently, wastewater disposal operations associated with oil and natural gas production have been identified as a probable cause of seismic events felt in Ohio and Oklahoma.

In California, where there is frequent natural seismic activity, additional concerns pertaining to seismic hazards include the effects of large natural earthquakes on the integrity of storage sites, and the potential for storage to exacerbate the severity of natural earthquakes. From an operational standpoint, it is also important for a project developer to be able to differentiate between natural events and those induced by injection operations.

To date, there is only one instance in California in which regulators have dealt with the issue of seismic hazards associated with CO_2 storage. In response to requests by local permitting authorities in 2010, WESTCARB analyzed the potential risk of induced seismicity from a proposed small-scale 6000-ton injection at 10,000 feet of depth in the Montezuma Hills area of northern California. The work, done in collaboration with C6 Resources as part of Phase II, included identifying active faults in the vicinity of the injection site and simulating the pressure change effects of the proposed CO_2 injection. The assessment predicted that the area surrounding the injection well over which the pressure change would occur would not intersect any known faults. The overall pressure changes predicted would be too small to result in any noticeable induced seismicity. This study provided useful information for policymakers and regulators as a first-in-kind approach to risk assessment for induced seismicity in permitting CO_2 storage projects in California.

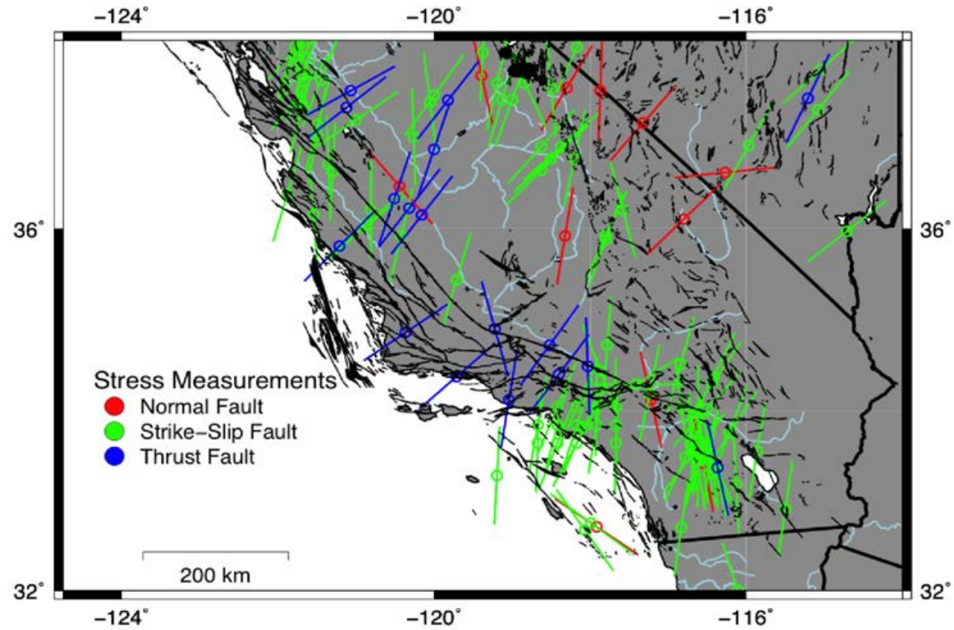
In 2011, as part of Phase III, WESTCARB conducted a seismic hazards workshop to elicit expert opinions on fruitful research areas to better inform development of future CO_2 storage regulations related to seismic risks. Held in conjunction with the American Geophysical Union conference in San Francisco, the workshop was attended by 14 international experts. The group included scientists who had worked on CCS projects in Japan that had experienced large, naturally occurring earthquakes. The workshop participants debated key questions, discussed what types of data and studies could best inform operational and monitoring practices to assess seismic hazard risk, how to monitor for seismic events during and after injection, and responses to mitigate induced seismic events should they occur at storage sites.

In follow-up to the workshop, in 2014, the Energy Commission funded a WESTCARB study at LBNL to research seismic hazards associated with CO_2 storage. The first task of the LBNL scientists was to determine the availability of the types of data required to perform seismic hazard risk assessment, and to review data quality and quantity. Figure 16, Figure 17, and Figure 18 show some of the relevant data that LBNL collected. Assembling an American Geophysical Union annual meeting follow-on group of international experts, LBNL held a critical project review in December 2014 to determine, based on data availability, what research would be most valuable for detailed studies in the second phase of the study.

One of the main recommendations of the review was to focus on developing a critical data set and analysis for a representative storage site in California. Given the richness of available data from King Island, this site was chosen. Several research efforts are currently underway:

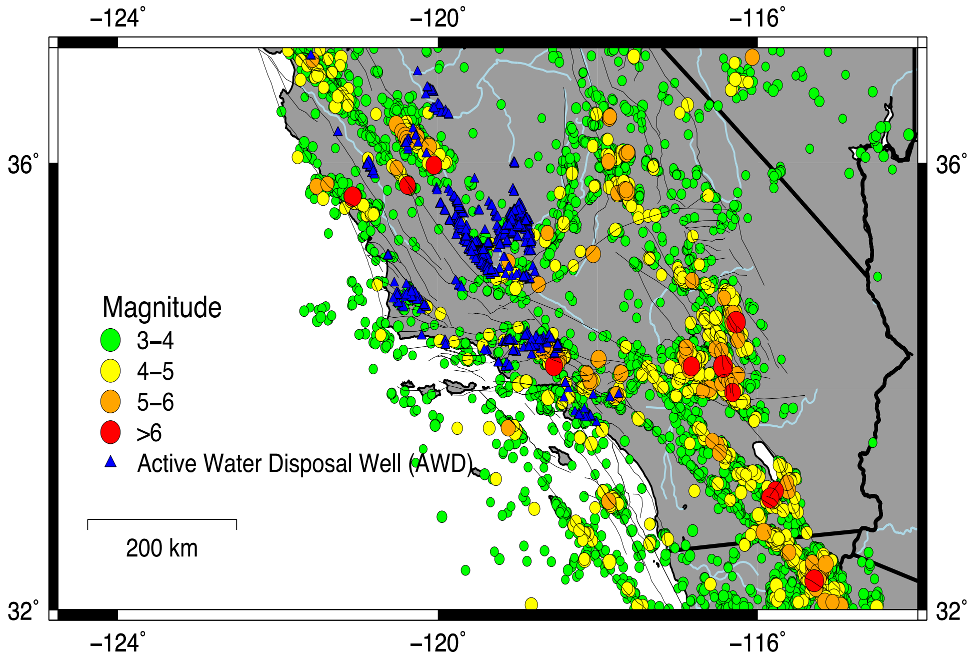
- Examine subsurface fault distributions for the reservoir using 3-D seismic profiles
- Expand on the existing King Island injection simulation to include seismic simulations, including simulated pressure history from injection
- Model the effects on pore pressure of gas volume changes due to mixing of CO_2 with the naturally occurring methane gas in the reservoir
- Perform fracture shear experiments on cores of the sealing shale formations to determine failure modes and mechanisms.

Figure 16: Quaternary and Younger Faults and Orientation of Maximum Horizontal Compressive Stress in California



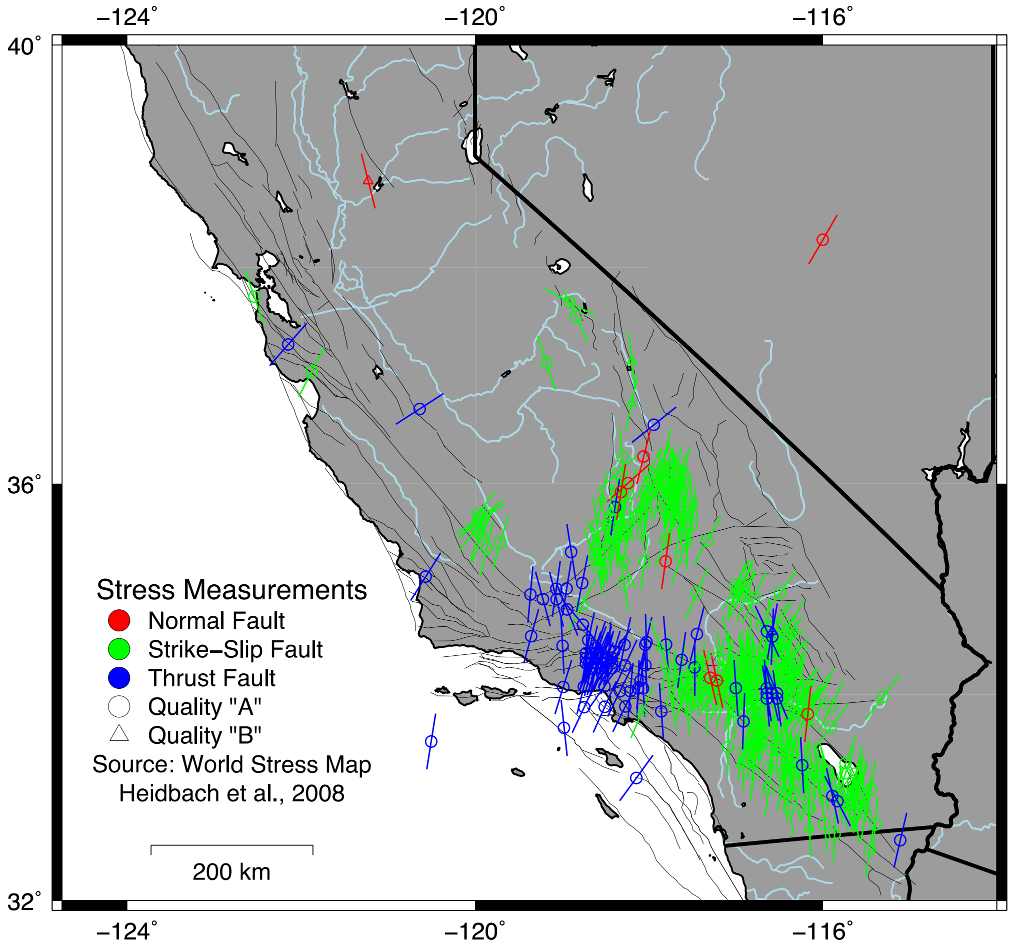
Stress data are taken from the World Stress Map (www.world-stress-map.org) and are color coded to indicate type of stress regime. Faults (shown in black) from the US Quaternary Fault and Fold Database.
Photo Credit: http://earthquake.usgs.gov/hazards/qfaults

Figure 17: Earthquakes M Greater than3 from the Southern California Earthquake Data Center Catalog of Waveform Relocations, 1981 to 2011



Quaternary and younger faults from the UCRF3 fault database shown in black.

Figure 18: Quality A and B Stress Measurements in California from the World Stress Map



CHAPTER 3:
CO_2 Utilization Potential

An assessment and "technology roadmap" of CO_2 utilization technologies was completed using technology readiness criteria and factors specific to California(Burton et al., *Research Roadmap of Technologies for Carbon Sequestration Alternatives*). Recommended technologies are those expected to reach commercialization commensurate within the time frames set for California's emissions goals in 2020 and 2050 and which have the potential to make significant contributions to the state's required GHG reductions.

For the roadmap, beneficial CO_2 utilization was defined to include technologies that produce a useful product directly from captured anthropogenic CO_2 or in connection with the processes of capture or sequestration of CO_2 (Table 1). By this definition, capture technologies are out-of-scope unless they produce a product as part of the capture process. Geologic sequestration likewise is not included except in cases where something of value, such as additional oil, gas, geothermal heat, or water, is a by-product.

3.1 Methods

A Roadmap Working Group was created to establish the assessment methods and knowledge base necessary to inform the roadmap. The members consisted of experts in energy technology commercialization, in beneficial use technology research and development, and in carbon capture and sequestration technology development and deployment. An impartial committee of reviewers assisted the working group in ranking the technologies.

To assemble the knowledge base to inform the roadmap, the working group searched the published literature using science and technology search tools available through the national laboratories and University of California libraries, interviewed technology developers and vendors, and conducted patent searches. In addition, program managers of previous and existing beneficial use research grant programs were contacted to establish lessons learned and opportunities for leveraging any future California investments.

To evaluate each technology, inputs to the process (CO_2 and other components including water), process attributes and outputs from the process (products and other components, including waste products) were identified. Attributes of the process included identifying existing suppliers/developers and opportunities to deploy the process within California. These factors were then supplemented with additional parameters specific to each technology and used to rate technology readiness, barriers to deployment, knowledge gaps, maturity, availability of life-cycle analyses, environmental impact, water use, and economic benefits. 1 contains a list of the technology categories that were evaluated.

Table 1: Categories of Beneficial Use Technologies

Categories	Technology Description
CO_2 as a working fluid	Enhanced oil recovery (EOR) Enhanced gas recovery (EGR) Enhanced coal bed methane recovery (ECBM) Enhanced geothermal systems (EGS)
CO_2 for Building Materials Manufacture	Carbonates and other construction materials
Biochar	Pyrolysis of biomass
Fuel and Chemical Production (e.g., urea fertilizer, synfuels)	Chemical Conversion Biological Conversion
Power Generation Applications	Supercritical CO_2 for Brayton Cycle Turbines Working fluid / cushion gas for energy storage
CO_2 as a Solvent	Supercritical fluid extraction and other food processing applications Dry cleaning
CO_2 in Agriculture and Biomedical Applications	Greenhouse atmosphere additive Grain silo fumigant Sterilization for biomedical applications
Miscellaneous Industrial Applications	Fire extinguishers Shielding gas for welding Refrigeration and heat pump working fluid Propellant Rubber and plastics processing – blowing agent Cleaning during semiconductor fabrication
Water from displaced aquifer fluids	Water purification Extraction of Value Added Solids from Water

3.2 Results

The first finding of the study was that there currently is no systematic set of data or existing methodology to enable comparison of the various technologies. Each technology has key advantages and disadvantages, but their relative importance can only be qualitatively inferred. This is particularly problematic when comparing direct uses, such as working fluids, with indirect uses such as freshwater production from saline aquifer fluids. A consistent method for life-cycle analysis is needed for each technology that lays out the relative merits, energy and resource requirements, and carbon reduction benefits in a quantified way.

Table 2 provides a summary of rankings. These rankings gave highest marks for biological conversions, treatment of displaced aquifer fluids, building materials, and EOR or EGR applications.

Table 2: Summary of Technology Rankings

Rank	Technology
A	Biological Conversion Treatment of displaced aquifer fluids EOR and EGR Building materials Working fluids for energy storage
B	Geothermal working fluid Chemical conversions Working fluids for energy generation

For California, beneficial use technologies could provide important contributions to the state's overall greenhouse gas reduction strategy in ways beyond providing permanent sequestration of large volumes of carbon, which is the traditional metric for evaluating geologic sequestration. These include:

- Integrated projects where capture provides a CO_2 supply for CO_2 utilization facilities that provide local community benefits such as jobs, while the bulk of the captured stream may be geologically sequestered.
- Potential to address smaller volume or dispersed sources that are not amenable to capture and storage and which, in aggregate, may provide significant greenhouse gas reduction volumes.

In this context, the overarching issues to be addressed include:

- Verification of sequestration for the products created, including a life-cycle analysis of carbon and energy use.
- Establishing accounting protocols to verify sequestration and life cycle so that technologies can be demonstrated to clearly contribute to cap-and-trade requirements.
- Studies to establish the best sites in the state for investment in integrated infrastructure. These may combine multiple sources and geologic and beneficial use sequestration options to realize economies of scale, local benefits, and climate change goals most effectively.

Three strategies were identified as having potential to increase the flow of federal funding into California: (1) to provide state funds to meet the requirements for matching funds for federal projects; (2) to encourage teaming of outside institutions and organization with California-based companies, in particular biotechnology companies; and (3) to allow California sites to be used as demonstration facilities for beneficial use technologies.

CHAPTER 4: CO_2 Point Source Database

DOE's National Energy Technology Laboratory (NETL) produces an atlas of carbon storage for the United States and Canada. The atlas is a compendium of materials from the seven DOE Regional Carbon Sequestration Partnerships and has been published biennially since 2006. NETL also established NATCARB, a web database where point source data and geologic storage data can be downloaded and utilized by stakeholders or researchers through several interactive applications.

The audience for these publications is predominantly non-technical federal policymakers and the public. In particular, the atlases serve as important communication pieces for congressional staff and others who seek a comprehensive overview of CCUS activities in their political regions. Key data provided by the RCSPs include geologic storage estimates by state/province, CO_2 emissions from point sources, pilot and demonstration project findings, and outreach efforts.

WESTCARB's activities included updating both the point source and geologic storage data pertaining to its region for NATCARB and the atlas publications. WESTCARB also maintains a web interactive regional database, the WESTCARB Carbon Atlas (http://www.westcarb.org/carbonatlas.html).

4.1 Updates to the Database

During Phase III, substantial updates and revisions to the WESTCARB CO_2 sources database were performed as part of WESTCARB's submission to the 2012 United States Carbon Utilization and Storage Atlas—Fourth Edition (Atlas IV) and the NATCARB stationary source database (http://www.natcarbviewer.com/).Updates included the addition of about 250 facilities, which brought the total facility count to over 500 within the region. NATCARB released the initial source data set for Atlas IV in late 2012 and a revised data set in April 2013.

WESTCARB issued a report *Compilation of CO_2 Point Source Data for the WESTCARB Region,* which summarizes its point source work including the references used to compile data on stationary CO_2 emissions sources within the region. The report also provides observations and recommendations for future improvements in the consistency and utility of the database. A significant effort was invested in resolving discrepancies between data in different data sets. Differences included location data (latitude and longitude), variation in facility names and scope of facilities reported for different programs or reporting years, and variations between facility identifying numbers used in different databases. A close examination of year-to-year variations in facility emissions helped avoid significant omissions, under-representation, or over-representation of emissions for individual facilities and source types. The report also contains recommendations for increasing the accessibility and value of downloadable data, standardizing nomenclature and content of sources, enhancing source mapping capabilities, and better communicating the significance of data fields and facility characteristics.

The WESTCARB point source database includes information on the largest industrial emitters of CO_2 in the WESTCARB region. The 2012 update primarily drew upon data from EPA's Greenhouse Gas Reporting Program (GHGRP) for the 2010 calendar year, the first year for which this reporting was required. CO_2 source data for British Columbia were obtained primarily from Environment Canada's Greenhouse Gas Emissions Reporting Program data set for the 2009 calendar year. These data sets were checked against existing WESTCARB and NATCARB data sets, EPA's eGRID data for power plants, and other sources.

The stationary source data sets, along with geographic information system tools for analyzing source proximity to potential CO_2 storage locations are available through WESTCARB's web-based Carbon Atlas and through NATCARB. For the Atlas submission, a final source data set was prepared, containing electric power sources meeting a 100,000 metric ton-CO_2 per year minimum emission threshold and other sources meeting a 50,000 metric ton-CO_2 per year threshold.

4.2 Source Types

Electric power plants and cogeneration units are the predominant stationary CO_2 source types in the WESTCARB region, producing about 70 percent of CO_2 emissions from major stationary sources. As shown inTable 3 andFigure 19, they are the largest source category in each WESTCARB state except Alaska, where petroleum and natural gas facilities (production, processing, and transportation) are the greatest contributors to CO_2 emissions. The same is true for British Columbia. The fuel mix for electric power plants varies considerably between states. Arizona is home to some of the region's largest coal-fired plants, whereas natural gas combined cycle plants are predominant in California and significant in several other states. Hawaii relies chiefly on oil-fired generation.

In California, power plants are dominant, but oil refineries, chemical plants, cement and lime plants, and oil and natural gas processing facilities are also important. Significant fractions of Washington's CO_2 emissions are also produced by oil refineries as well as other industrial facilities, particularly pulp and paper mills. Throughout the WESTCARB region, CO_2 emissions also derive from institutional heating and cooling plants, landfills, agricultural processing plants, mineral and metal processing facilities, ethanol fermenters, and fertilizer plants.

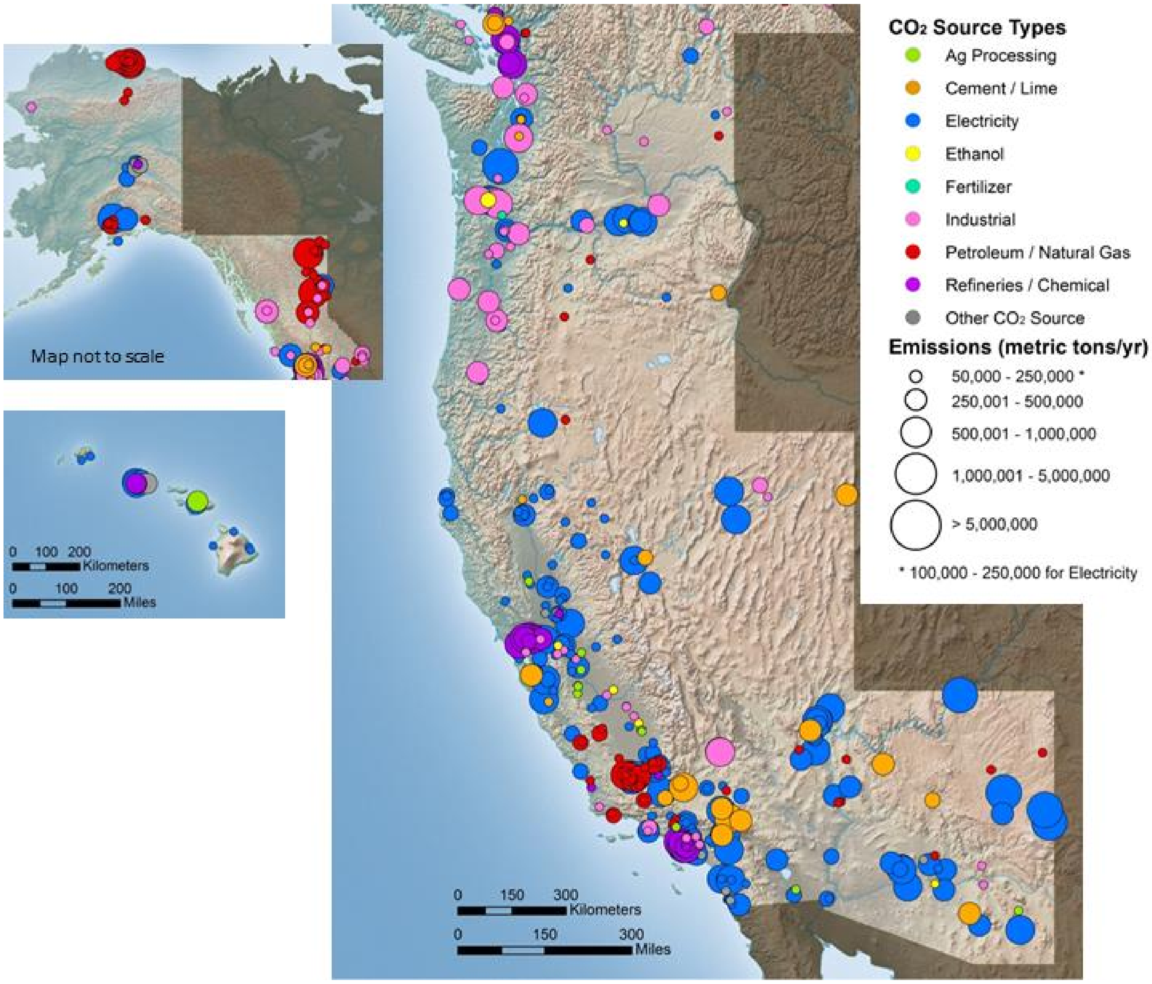
In Alaska, oil and natural gas processing dominate CO_2 emissions. Oil refining is also a major emission source in California. Throughout the region, other significant industrial CO_2 sources include cement and lime plants, aluminum smelters, ethanol fermenters, steel mills, and fertilizer plants.

Table 3: Large Stationary Source CO_2 Emissions in the WESTCARB Region (Millions of Metric Tons of CO_2 Per Year)

State/ Province	Power & Cogen Plants	Refineries & Chemical Plants	Petroleum & Natural Gas	Cement & Lime Plants	Other Industrial	Ag Process/ Ethanol/ Fertilizer	Source Type Totals
Alaska	3.9	0.8	10.2		0.2		15.0
Arizona	66.6		0.4	2.2	0.3	0.3	69.7
British Columbia	1.5	0.6	4.3	1.4	3.1		10.9
California	101.2	33.7	9.3	7.8	3.2	1.1	156.2
Hawaii	10.7	1.1				0.7	12.4
Nevada	23.2		0.1	1.8	0.3		25.4
Oregon	13.4		0.2	0.6	4.5	0.6	19.4
Washington	15.3	6.3	0.2	0.6	8.7		31.1
Totals	235.8	42.5	24.7	14.32	20.3	2.6	340.1

Sources: 2012 United States Carbon Utilization and Storage Atlas – Fourth Edition.
http://www.epa.gov/ghgreporting/documents/xls/summary_2010_GHG_data.xlsx; first posted in Fall 2011.

Figure 19: Large Stationary CO2 Sources in the WESTCARB Region



WESTCARB CO_2 emissions from large stationary sources estimated in Atlas IV were 340 million metric tons per. Figure 20 illustrates these emissions by state, province, and facility type.

Table 4 shows the total CO_2 storage resource estimates (saline formations, oil and gas reservoirs, unmineable coal seams) by state or province in the WESTCARB region. The region's saline formations alone have the potential to store hundreds of years' worth of CO_2 emissions from stationary sources. Although the overall storage resource represented by oil and gas and unmineable coal is much smaller, CO_2 injection and storage in these reservoir types has the potential to create economic benefits from enhanced hydrocarbon recovery. Projects may also be able to utilize existing infrastructure such as wells and pipelines, and take advantage of the prior geologic characterization work undertaken as part of oil and natural gas exploration and production.

Figure 20: WESTCARB Large Point Source CO2 Emissions by State, Province and Facility Type

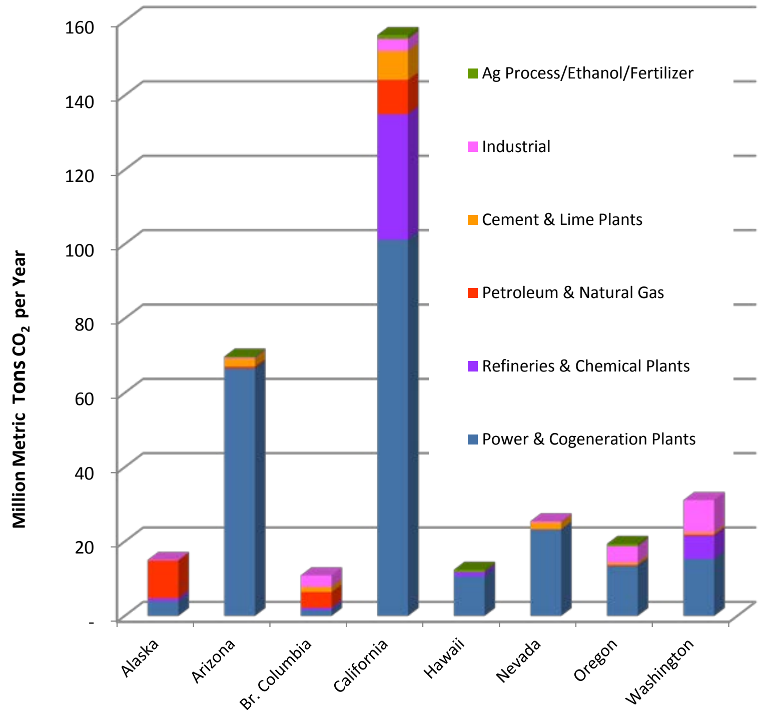


Table 4: CO2 Storage Estimates by State and Province in WESTCARB Region

State/Province*	Million Metric Tons		Million Tons	
	Low Estimate	High Estimate	Low Estimate	High Estimate
Alaska	8,640	19,750	9,520	21,770
Arizona	130	1,170	140	1,280
British Columbia	910	3,860	1,000	4,250
California	33,890	420,630	37,360	463,660
Oregon	6,810	93,700	7,510	103,290
Washington	36,620	496,730	40,360	547,560

*Hawaii and Nevada have yet to be assessed

CHAPTER 5:
CCS for Natural Gas Power Plants

The Energy Commission contracted Stone & Webster (subsequently acquired by Shaw and now part of CB&I) to assess the cost and performance impacts of the full CCS cycle for natural gas combined cycle plants in California (Holden, *Assessment of Natural Gas Combined Cycle Plants for Carbon Dioxide Capture and Storage in a Gas Dominated Electricity Market*) . These include CO_2 capture and compression, rights-of-way acquisition and construction of CO_2 pipelines, and CO_2 injection well field construction, injection, and monitoring. DOE also provided funding to Lawrence Livermore National Laboratory to assess the suitability of subsurface geology to support geological storage in the vicinity of California's utility-scale NGCC plants (Myers et al., *Geologic CO_2 Sequestration Potential of 42 California Power Plant Sites*).

CB&I surveyed over 115 developers or researchers of CO_2 capture and compression technologies, which varied from emerging technologies to processes that are commercially mature in other industries. Based on this review, CB&I concluded that a likely near-term application for California design conditions could be best represented by a post-combustion capture system, with dry cooling used for heat rejection from the capture and compression processes. Representative performance and cost characteristics were incorporated into a commercial NGCC plant performance model to evaluate the primary study cases for retrofit and new-build applications. Evaluations were also performed for alternative configurations employing flue gas recycle (FGR, also sometimes called exhaust gas recycle) and wet or hybrid wet-dry cooling systems for the CO_2 capture and compression process units.

CB&I selected one existing plant and one proposed new plant as sources for site-specific data, and developed performance and cost information using site characteristics along with generic design details. CB&I then performed site-specific engineering assessments of the performance and cost impacts associated with CCS. The life-cycle cost of electricity and cost of CO_2 avoided (cost per ton) for the specified design conditions were estimated. Sensitivity analyses examined the effect of variations in key economic and performance assumptions.

5.1 CO_2 Capture Technology

Post-combustion capture is currently expected to be the easiest of the three types of capture processes to integrate with most existing NGCC plants. Although post-combustion CO_2 capture cannot be considered widely proven at utility power plant scale, capture processes have been demonstrated widely at large pilot or pre-commercial-scale facilities.

Special design conditions for many California locations include high summer ambient temperatures, limited availability of water, and the requirement for dry cooling.

In the initial CB&I analysis, the requirement for dry cooling necessitated the use of costly CO_2 capture system cooling water refrigeration to meet a design criterion of 90 percent CO_2 capture on all but the hottest summer days. Specifically, the capture system cooling water would be chilled in order to maintain the absorption process in the temperature range required to attain a 90 percent capture rate. For an NGCC plant using air-cooling for chiller heat rejection, there were substantial increases in net heat rate, LCOE, and cost of CO_2 avoided. To mitigate this impact, the CO_2 capture system design was revised to achieve 90 percent capture at an annual average ambient temperature design point. For a dry-cooled system, substantial savings resulted from relaxing the capture effectiveness criterion to 90 percent CO_2 capture on an average day. Although such a capture system would then remove less than 90 percent of the CO_2 on hot days, this would be acceptable with a flexible regulatory structure and would be suitable for applications where the captured CO_2 was used for other beneficial uses such as EOR. In situations where modest amounts of cooling water were available, such as reclaimed wastewater treatment plant effluent or other gray water, the CO_2 capture process unit would achieve the best performance and lowest cost.

Recycle of a portion of the flue gas back to the combustion turbine (CT) inlet increases the flue gas CO_2 concentration and reduces the flue gas flow to the CO_2 absorber. Although studies by others suggest this approach could yield savings in the CO_2 capture system capital costs and energy requirements, CB&I found that the simplest approach—use of a direct contact cooler in the recycled flue gas ducting leg—may not provide the best performance results.

Alternative "pre-combustion" approaches to CO_2 capture were also reviewed. These are akin to technologies employed in the chemical processing industry for the production of plastics or hydrogen from natural gas. Relative to post-combustion approaches, there are fewer technology developers, and successful application typically involves modification to CTs in the base NGCC plant. In particular, the fuel composition is shifted to predominantly hydrogen rather than methane. Although some CT manufacturers have made progress with hydrogen combustors, it appears further research, development, and demonstration effort is needed to commercialize a CT that operates efficiently and reliably on hydrogen fuel without nitrogen from an air separation unit available as a diluent and supplemental motive force (as is the case in integrated gasification combined cycle). Cost-competitiveness is a concern too.

Fuel combustion in high-purity oxygen, rather than air, is used in some novel combined cycle technologies. Academic studies and combustor-level bench testing have been performed for "conventional" NGCC oxy-combustion approaches, which dilute the oxygen at the combustor with recycled flue gas. Another oxy-combustion approach uses chemical looping with oxygen. Oxy-combustion approaches reduce the volume of post-combustion gases that must be treated for CO_2 separation. Given their application to date at pilot scale, oxy-combustion processes are more difficult to model at scale for evaluating cost and performance impacts in the manner used for post-combustion capture, although such evaluations are usually available from the technology developers. Costs for oxy-combustion support equipment, such as air separation units or condensers to separate moisture from CO_2, are well known.

Oxy-combustion appears to offer future promise if unique equipment can be successfully and economically scaled up and if the high cost and auxiliary power requirements of oxygen production can be addressed. Considerable development efforts are under way, particularly for units at the small end of utility scale that could be sited in or near oilfields where the separated CO_2 can be used for EOR operations.

5.2 CO_2 Pipeline Transportation and CO_2 Storage

The technical and regulatory issues associated with CO_2 pipeline transport and CO_2 injection and monitoring appear to be relatively minor components of the overall cost of CCS for the NGCC sites evaluated. The pipeline costs are relatively predictable, at least for flat rural settings. Large-capacity CO_2 pipelines have been used for over 40 years in EOR operations and there are over 4,000 miles (6,400 km) of such pipelines in the United States.

Although California does not currently have a formal framework to address CO_2 pipeline permitting, design, and operation, the issues of CO_2 pipeline safety are within the jurisdiction of the State Fire Marshal. There remains an opportunity for policymakers to draft appropriate statutes or regulations to assure safety and optimized routing, as well as authorizing the use of eminent domain for CO_2 pipeline rights-of-way acquisition where needed.

The availability of geologic reservoirs with sufficient CO_2 storage capacity and the cost of construction and UIC of CO_2 injection and monitoring wells appear not to pose significant barriers to CCS for many California NGCC plants. Nonetheless, there are some regulatory, permitting, and legal uncertainties that could slow the development of storage sites. These include acquisition of pore space use rights for storage, particularly when spanning a significant number of landowner parcels; permitting of Underground Injection Control (UIC) Class VI CO_2 injection wells, particularly for wells initially permitted as UIC Class II for EOR operations; and long-term liability for injected CO_2.

Still, the estimated engineering, procurement, and construction costs for the CO_2 transportation and injection systems, under both the retrofit and new build scenarios, were less than 5 percent of the total EPC costs for the CCS system.

5.3 CCS Performance and Cost Impacts

The impact of retrofitting CCS to a reference NGCC plant in California would entail about a 15 percent reduction in the "net" generating capability (for example, power delivered to the grid) because some of the steam and electricity produced by the base NGCC plant is used by the CO_2 capture and compression process units. The net capacity reduction for a comparable new-build NGCC facility would be less, about 11 percent, because of greater opportunities to optimize the integration of the CO_2 capture and compression systems into the plant design. Similarly, the use of steam and power to capture and compress CO_2 reduces the overall net efficiency of an NGCC power plant. Measured as an increase in net heat rate, this impact is about 17 percent for the retrofit case and about 12 percent for the new-build case.

The total EPC cost for installing CCS at a new build, nominal 600 MW NGCC plant in California is about $900 million. The total EPC cost includes the CO_2 capture and compression systems as well as the CO_2 pipeline and injection systems. This cost is higher than the costs at other typical U.S. locations due to the requirement for dry cooling, higher labor costs, and use of an EPC contracting structure instead of an EPCM contracting structure. The latter monetizes more of the risk in the cost estimate. The LCOE for the new-build NGCC facility was estimated to increase by approximately 35 percent due to the addition of the CCS system. A reduction in future capital costs by 30 percent would result in an approximately 25 percent decrease in the LCOE adder for CCS. Reducing the cost of financing, through government loan guarantees for example, could further reduce LCOE.

5.4 NGCC-CCS Cost Comparisons

With the objective of providing context for the NGCC-CCS engineering-economic evaluation study, WESTCARB compared it to other publicly available studies of the economics of CO_2 capture technologies applied to NGCC power plants. In particular, the "unitized" cost ratios for NGCC plants with and without post-combustion CO_2 capture were compared from available studies with the aim of screening out location-specific cost variability that would otherwise affect absolute cost comparisons.

The resulting ratios, shown in Table 5, indicate that the capital cost of CO_2 capture and compression equipment is large, on the same order of magnitude as the cost of the base NGCC plant itself. This suggests that maintaining high capacity factors will be paramount in NGCC-CCS economics.

The cost ratios in Table 5 also show that the WESTCARB study by CB&I had the highest cost "premium" for CO_2 capture and storage. It is believed that the costs for post-combustion CO_2 capture for NGCC plants may be higher in California than other locations because of requirements for dry cooling (which no other study used), hot summer weather, and relatively higher replacement power costs. The WESTCARB study also used an alternative approach to contracting, which as noted earlier, CB&I believed was more commercially likely than the EPCM approach used in other cost studies.

To estimate storage costs, this study used a 45-year life-cycle cost of CO_2 storage and the \$/ton-CO_2 levelized cost for a USEPA UIC Class VI-compliant well, based upon an injection near Lodi, California, which utilized well logging data collected by Schlumberger from the WESTCARB "Citizen Green" geologic characterization at King Island (see Chapter 5).

The costs are relatively favorable at less than \$2 per ton-CO_2 on a levelized basis, meaning that if CO_2 can be captured economically, the transportation, injection, storage, and monitoring components will not be cost-prohibitive.

Table 5: Comparison of Capital Costs from NGCC-CCS Studies

	EPC Cost Comparison for NGCC with CCS		Comments
Study	Ratio of capital costs ($ capture / $ no capture)	Ratio of capital costs ($/kW-net basis)	
CB&I Adv Amine	2.28	2.62	California Central Valley site; dry cooling
IEA MEA	1.91	2.20	50 Hz 9F CTs; wet cooling tower
IEA MEA-FGR	1.74	2.02	50 Hz 9F CTs; wet cooling tower*
IEA Adv Amine	1.62	1.83	50 Hz 9F CTs; wet cooling tower
EPRI/Aker Adv Amine	1.88	2.15	Upper Midwest site; wet cooling tower
EPRI/Aker Adv Amine-FGR	1.80	2.03	Upper Midwest site; wet cooling tower
NETL MEA	1.80	2.13	Midwest site; wet cooling tower
NETL MEA-FGR 35%	1.56	1.82	Midwest site; wet cooling tower
NETL MEA-FGR 50%	1.64	1.90	Midwest site; wet cooling tower
NETL Adv Amine-FGR 35%	1.57	1.80	Midwest site; wet cooling tower

* Does not include gas turbine modifications for FGR

The cost of CO_2 injection and storage in a favorable location in California's Central Valley appears to be lower than that for the locations used in other studies because of the proximity of storage locations to emission sources, flat rural terrain, highly permeable sandstone formations (allowing the use of fewer injection wells), and an established infrastructure from oil and natural gas exploration and production.

Further assessment of storage costs applied data from Schlumberger Carbon Services to a representative California NGCC power plant, the 280-MW Lodi Energy Center (Row et al., *Economic Assessment of Permanent Geologic Storage of CO_2 From a California Natural Gas Power Plant*). The CO_2 captured at the plant over an economic life of 30 years is approximately 1,000,000 tons of CO_2 per year, which served as the basis for the cost analysis. Breakouts were provided for the following cost categories:

- Regional geologic site characterization
- Site-specific geologic site characterization
- Monitoring plan, installation, and baseline surveys
- Infrastructure and injection well construction

- Area of review study and corrective action
- Annual injection operations
- Operational monitoring program
- Post-injection well plugging, equipment removal, and site care
- Financial responsibility

The assessment yielded a cost of $1.68 per ton of CO_2 stored (2014 dollars). This included pipeline transport but did not include CO_2 capture, purification, compression, and dehydration.

CHAPTER 6:
CCUS Implementation Issues

During Phase III, WESTCARB produced two reports examining the status of CCUS in the WESTCARB region and assessing factors affecting successful commercialization:

1. Assessment of the Barriers and Value of Applying CO_2 Sequestration in California (Burton, et al., *Assessment of the Barriers and Value of Applying CO_2 Sequestration in California*).
   This report served as a follow-on to the AB 1925 report to provide an update on CCUS developments and the lessons from several proposed CCUS projects in California.
2. Regional Technology Implementation Plan: Carbon Capture, Utilization, and Storage in the WESTCARB Region – Status Assessment (http://www.westcarb.org/pdfs/2012_WESTCARB_Regional_Technology_Implementation_Plan.pdf). This report examined factors affecting the success of CCUS technology deployment in the WESTCARB region.

6.1 Assessment of the Barriers and Value of Applying CO_2 Sequestration in California

California regulatory agencies and policymakers have acknowledged the potential importance of CCUS technology to assist in meeting the State's GHG emission reduction goals. However, CCUS has not been given as high a priority as many other mitigation technologies when it comes to incentivizing its adoption through policies or regulation.

The study team reviewed the case for implementing CCUS in California based upon recent technical advances, economic conditions, and GHG mitigation strategies both within California and in other parts of the world serving as examples from which to adopt or reject. The following questions and responses summarize the report's conclusions:

1. In what sectors does CCUS have the most potential to assist the state in reducing its CO_2 emissions?

CCUS has potential application to the power, industrial, and transportation sectors in California. Studies show that increasing electricity demand will continue, with aggressive energy efficiency measures expected to contribute only about half of the GHG reductions necessary by 2050. For oil refineries and cement plants, there are no options other than carbon capture to address process-related emissions. Applications to transportation, including to biofuels, hold promise to create net-negative emissions to assist in offsetting emissions from sources where no existing technology or method exists to reduce emissions.

2. Do policies to facilitate CCUS enable continued use of fossil fuels even where there may be other viable options for energy generation?

Given the substantive efforts underway to diversify California's energy portfolio away from carbon-intensive fossil fuels, it appears likely that CCUS may only be included by policy when studies have demonstrated that no other options are available to decarbonize the electricity, transportation, or industrial sectors. Given that both transportation and industrial sectors are likely to decarbonize, in part, by using carbon-free electricity, these sectors will become dependent on the power sector for their energy supplies. Thus, it will become even more vital to California's economy to assure the reliability and sustainability of low-cost electricity supplies.

Facilitating CCUS should not be viewed as a substitute for non-fossil-fuel-based solutions to reducing GHG emissions in contributing economic sectors. However, economies' use of fossil fuels since the start of the Industrial Revolution is designed to take advantage of the benefits that fossil fuels provide. Among these benefits are high energy density, on-demand power generation, and relatively low cost. As fossil fuels have been exploited to improve economic well-being, there have been downsides—local to global environmental consequences and, in particular, CO_2 increases leading to an unprecedented and unintended global experiment in climate change.

Considering potential difficulties of integrating significant fractions of renewable energy resources, nuclear, and smart grid systems, CCUS could provide a compromise solution for economies to remain strong while eliminating one of the negative consequences of continued fossil fuel use. CCUS is not a substitute for development of CO_2-free technologies, but it warrants consideration and inclusion by policymakers as a bridging technology.

3. Are CCUS technologies, specifically subsurface storage elements, safe and effective over the long term?

CCUS projects worldwide and analogous technology projects provide data supporting the assertion that CO_2 can be stored safely in the subsurface for sufficiently long periods of time to mitigate climate change. Furthermore, these projects have tested a number of tools, including monitoring technologies, simulations, well completion methods, and well and cap rock integrity monitoring to give regulators confidence that risks can be measured and monitored. For California, areas of particular concern are assuring safety of groundwater resources from contamination and seismic hazards, including whether pressure buildup can induce felt-earthquakes and if the presence of stored CO_2 could exacerbate risks of natural seismic hazards.

4. How can California agencies and lawmakers assure that CCUS projects are appropriately permitted, regulated, monitored, and verified?

Regulations and statutes require some changes to accommodate permitting and regulatory oversight of CCUS projects. There is a robust and growing body of knowledge worldwide that can be drawn upon to formulate permitting and regulatory requirements that assure the safe and effective operation of CCUS projects. With the enactment of policies requiring attention to climate change impacts, agencies are now tasked with safety and effectiveness responsibilities that encompass both traditional local environmental and global climate change mitigation responsibilities.

An important priority for regulation is including CCUS as an option for meeting obligations set by compliance or standard requirements. Beyond recognizing CCUS as an option, methodologies that describe how storage or utilization technologies account for CO_2 must be established so that project developers can incorporate them into business cases. Policies that support a sustainable and predictable value for CO_2 are critical to enabling CCUS technologies.

5. Can the state's industrial and energy infrastructure accommodate the changes necessary to integrate CCUS?

Infrastructure requirements for CCUS will require the addition of capture facilities at CO_2 emission sources, pipelines, and injection and monitoring wells at storage sites. In addition, a labor force with expertise in power plant, pipeline, and well drilling engineering is necessary.

California will require substantial investment in pipeline infrastructure for CCUS to become widespread. Because a readily available supply of low-cost CO_2 would benefit California's oil industry, that industry and federal subsidies for oil production may be sources of capital for pipeline development. California's CCUS project developers may be able to repurpose or co-utilize some existing infrastructure at California's numerous oil and natural gas fields if storage is done in conjunction with CO_2-EOR or by conversion of depleted reservoirs to storage sites. Storage in saline formations will require new infrastructure and development to assure safe and effective long-term storage. California has a plentiful geologic storage resource to accommodate captured emissions, according to studies by the California Geological Survey.

California's labor force includes people with the right expertise to support a CCUS industry. The state is home to many small start-up companies, universities, and other research organizations developing utilization technologies. The Energy Commission has already made some R&D investments to support growth of this sector. More funding, possibly through cap-and-trade or EPIC programs, would accelerate development of more cost-effective capture and innovative utilization technologies.

6. If CCUS is to be relied on to reduce significant fractions of California's future emissions, at what rate should CCUS projects come on line, and what pathways to commercialization can accommodate this rate?

If CCUS is to be a viable option for the State to use to reduce GHG emissions to meet its 2050 goal, demonstration projects must be initiated within the next ten years. CCUS projects are capital-intensive industrial projects, which can require a decade to plan, finance, permit, construct, and commission. The size of each project needs to match the size of the point source, or number of point sources in the case of networks, that supply CO_2 to one or more storage sites. The number and size of these projects are further limited by the significant amount of public and private funding needed to develop any technology-proving demonstration project. The number of injection wells and additional pipeline to connect a well array will depend on the injectivity and storage capacity of the geologic storage formation(s); thus storage site development may continue for many years after injection operations begin.

Rates of CCUS technology adoption must be sufficient to contribute to a declining trend in California economy-wide GHG emissions with the right slope to intersect 80 Mt or less total emissions by 2050. It is an oversimplification to assume that technology adoptions between 2016 and 2050 will result in a linear reduction of emissions with time, but it serves to give a first-order approximation of the size of the task. With every year of delay in implementation of GHG reduction technologies, the slope becomes steeper. About 10 Mt per year must still be removed every year after 2020 to reach the 2050 goal. This is equivalent to removing several of California's largest point sources from the emissions inventory every year.

The most expedient way to enable CCUS from an economic and infrastructure perspective is to enable utilization of captured CO_2. The largest potential uses for CO_2 are for EOR, followed by building materials as a distant second. At current oil prices, CO_2-EOR faces some economic challenges, but when deployed, the state should benefit from substantive royalty revenues and job creation through the enhanced production that might be realized by using captured CO_2 in this way. Oilfield infrastructure might shorten the lead time for CCUS projects to become operational. While the need for crude oil-based transportation fuels will presumably decline dramatically between now and 2050, it is unlikely that the need for petroleum for manufacture of plastics and other materials will be eliminated by biologically based feedstocks. Estimates of CO_2-EOR potential in California's oilfields suggest that there should be a large enough demand for CO_2 (provided oil prices rise back to recent highs in the coming decades) to accelerate CCUS commercialization. Furthermore, building material CO_2 utilization technologies under development may prove to be a cost-effective way to separate CO_2 from power plant flue gas. Even though end products may not support paying high prices for CO_2, it may be a more cost-effective option for emitters than capture and sales for other utilization purposes.

7. In-state planning for future energy infrastructure, should CCUS be included as a component? What is the risk in not doing so?

California regulatory agencies and policymakers have acknowledged the potential importance of CCUS technology to assist the state in meeting its GHG emission reduction goals. However, CCUS has not been given as high a priority as many other mitigation technologies when it comes to incentivizing adoption through policies or regulation. Without actions to incorporate CCUS into the portfolio of accepted mitigation technologies, especially actions to develop accounting and regulatory methodologies, it will become less likely that enough CCUS projects will be up and running to contribute substantive emissions reductions in time to meet 2050 goals. All studies done to date of California's future energy options suggest that the 2050 goal cannot be met without CCUS; therefore, the risk of missing the target is high unless CCUS is included. Inclusion of CCUS means adding it to planning of future energy infrastructure.

Admittedly, because CCUS is a composite of technologies and has numerous applications, accommodating it in planning is a complex task. Given the complexity of future energy infrastructure and the extreme nature of its makeover over the next decades, it will be almost impossible to patch in additional technology options after long-term plans are adopted. For these reasons, California will lower its GHG emissions risk by accelerating policy, regulatory, and practical actions that enable CCUS as a GHG emissions reduction option.

6.2 Regional Technology Implementation Plan

The *Regional Technology Implementation Plan: Carbon Capture, Utilization, and Storage in the WESTCARB Region: Status Assessment* (RTIP) examined factors affecting the success of CCUS technology deployment in the WESTCARB region (http://www.westcarb.org/pdfs/2012_WESTCARB_Regional_Technology_Implementation_Plan.pdf). The report, which covered geologic, terrestrial, and carbon utilization options, addressed a regional audience of state and provincial policymakers, public interest nonprofits, regulated industries, project developers, or others with an interest in CCUS.

The RTIP process was initiated by eliciting stakeholder views at WESTCARB's 2010 annual meeting, which was attended by 80 representatives drawn from WESTCARB's membership. Attendees identified paths to commercialization and mapped a vision to a timeline with a sequence of milestones. In addition to the guidance provided by these discussions, WESTCARB drew upon Phase I and II findings and third-party CCUS sources to produce the RTIP.

The report summarizes regional characterization findings by state. Estimated storage potential in the WESTCARB region's broadly distributed sedimentary basins is enough to hold hundreds of years of CO_2 emissions from industrial sources. Opportunities for long-term CO_2 storage combined with enhanced oil recovery have been identified in southern California and Alaska. CO_2 storage in coal seams, along with enhanced coal bed methane production, may prove possible in Alaska, Oregon, and Washington. Studies matching industrial CO_2 sources to potential geologic storage locations indicate generally moderate distances for pipeline transport between the two.

Barriers to deployment in the region identified in the report included a lack of climate change legislation nationally to serve as a policy driver or lack of clear pathways for CCS adoption where climate change legislation exists (for example, California); relatively high costs for CO_2 capture and compression; and uncertain ownership under state or federal law of pore space rights in candidate CO_2 storage formations and potentially high transaction costs for pore space rights acquisition.

Deployment of geologic storage as part of CO_2-EOR is possible in the oil producing regions of California and Alaska. In California, sufficient volumes of affordable CO_2 relative to the price of oil are not available locally, and CO_2 pipeline transport from outside the state has not been economic. Thus, CO_2-EOR awaits the development of local CO_2 supplies via capture at industrial facilities and development of an in-state pipeline infrastructure. In Alaska, there are potential opportunities for CO_2-EOR on the North Slope if natural gas fields containing CO_2 are developed. At large scale, this would require construction of a proposed natural gas delivery pipeline. In oil fields near Anchorage, CO_2 supplies may come from anthropogenic sources.

Terrestrial carbon storage projects have been a staple of voluntary carbon markets since their inception. Public perception of terrestrial carbon storage is generally positive when it accords with land-use practices such as conservation and restoration. Many landowners are motivated to undertake projects both as a means of generating income and to improve their lands. Development and evolution of protocols and methodologies by independent carbon registries enable more project types to enter the voluntary carbon market and provide a basis for the development of offset protocols for compliance markets. Barriers to terrestrial carbon storage include limitations on support due to lack of climate change legislation or structuring of policy instruments, the ongoing need for standards to ensure the quality of offsets, and competition from other land uses.

CHAPTER 7: Conclusions

WESTCARB's Phase III studies built on the achievements in Phases I and II, refining storage estimates and providing a better understanding of the potential role of CCUS as a climate change mitigation option.

Results indicated that CCUS is a technically feasible solution that could contribute major GHG reductions from stationary CO_2 emissions sources. Overall, the WESTCARB region has substantial potential for geologic CO_2 storage, and studies indicate generally good alignment between large stationary CO_2 sources and sedimentary basins suitable for geologic storage.

In California, adoption of CCUS could be furthered by accelerating policy, regulatory, and practical actions in a timely manner to help meet the State's ambitious GHG reduction goals. Opportunities for CO_2 utilization in applications such as biological conversions, building materials, working fluids for energy storage, and enhanced oil recovery/enhanced gas recovery would be supported by the development of a systematic set of data or methodologies to enable meaningful comparison of the overall impacts of various technologies.

Application of CCS to California's NGCC plants may be uneconomic in the current market and regulatory environment. However, this situation could change as carbon allowance prices increase over time while the costs of CCS decline as the technology matures. Thus, support for NGCC-CCS through policy, funding, and pilot projects stands to benefit California by ensuring a robust portfolio of GHG reduction options.

GLOSSARY

Term	Definition
$/ton	Dollars per ton
Atlas IV	United States Carbon Utilization and Storage Atlas – Fourth Edition
BKi	Bevilacqua Knight, Inc
CB&I	Chicago Bridge and Iron Company
CCS	Carbon capture and storage
CCUS	Carbon capture utilization and storage
CF	Certification Framework
CGS	California Geological Survey
CIEE	California Institute for Energy and Environment
CMR	Combinable Magnetic Resonance
CO_2	Carbon dioxide
CT	Combustion turbine
DOE	United States Department of Energy
EGR	Enhanced gas recovery
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPC	Engineering, procurement, and construction
EPCM	Engineering, procurement, construction, and management
FEPs	Features, events and processes
FGR	Flue gas recycle
Ft	Feet
GHG	Greenhouse gas
GHGRP	Greenhouse Gas reporting Program
Hydrocarbon	A compound of hydrogen and carbon (main components of petroleum and gas)

LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized cost of electricity
m	Meters
mg/L	Milligrams per liter
Mt	Metric tons
MW	megawatt
NATCARB	National Carbon Sequestration Database and Geographic Information System
NETL	National Energy technology Laboratory
NGCC	Natural gas combined cycle
NGCC-CCS	Natural gas combined cycles-carbon capture and storage
O&M	Operation and maintenance
RCSP	Regional Carbon Sequestration Partnerships
Seismic attenuation	The absorption of seismic energy or the deviation from perfect elasticity
Shale	Fine-grained, clastic sedimentary rock made of mud and various minerals
TDS	Total dissolved liquids
UIC	Underground injection Control
USEPA	United States Environmental Protection Agency
WESTCARB	West Coast Regional Carbon Sequestration Partnership

APPENDIX A: Materials Produced during Phase III

Publications and Presentations

2010 Burton, E.A., Ezzedine, S., Reed, J., and Beyer, J.H. Accelerating Carbon Capture and Sequestration Projects: Analysis and Comparison of Policy Approaches. 10th International Conference on Greenhouse Gas Control Technologies. September 19-23, 2010, Amsterdam, The Netherlands.

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Videos

Educational videos were made about the Citizen Green project on King Island in California's Sacramento Basin and the research done by LBNL scientists on the extracted core and gas samples. The first video, *Carbon Capture and Storage Research in California: The Citizen Green Project,* provides an easy-to-understand overview of the project, and features the project's industry host (Princeton Natural Gas), a California Energy Commissioner, and two scientists from LBNL. Six shorter videos, aimed at a more technical audience, were produced as a series, *From Field to Laboratory: Qualifying a Geological CO_2 Storage Site.* These video segments highlight the well logging, core sampling, and data collection done in the field and the laboratory testing that helps to determine whether a site can securely store CO_2.

A new YouTube channel was created to facilitate access to the videos:
http://www.youtube.com/user/WESTCARBvideos/videos
with links provided on WESTCARB's website, as well.

The videos were also shown at WESTCARB's booth at the Annual CCUS Conference in Pittsburgh, PA, in 2012 and 2013.

Webpages

Creation of new webpages and modifications to existing pages were ongoing throughout Phase III to ensure viewers had access to up-to-date WESTCARB information and results, as well as information about relevant third-party CCUS projects and research.

New webpages included:

- Assessment of CCS for Gas-Fired Power Plants (the California NGCC-CCC study)
- CO_2 and Climate Change (providing basic facts on CO_2 and climate change information)
- Carbon Utilization
- Videos and a new WESTCARB YouTube Channel
- Citizen Green Well: Geologic Characterization in the Sacramento Basin, California

This Citizen Green webpage featured a description of the geologic characterization project on King Island, as well as providing "Bytes from the Bit," synopses of daily drilling reports and photos, which were added during field work to allow visitors to track the progress of the drilling, well logging, and coring. When the project videos later became available, these were also added to these webpage